PUBLIC SERVICE COMMISSION OF WISCONSIN

STRATEGIC ENERGY ASSESSMENT DRAFT REPORT

ENERGY 2014

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To the Reader

This is the fifth biennial Strategic Energy Assessment (SEA) issued by the Public Service Commission of Wisconsin (Commission or PSC), an independent state regulatory agency, whose authority and responsibilities include regulatory oversight of electric service in Wisconsin. The SEA provides a picture of past and future electric energy needs and sources of supply. It brings to light issues that may need to be addressed to ensure the availability, reliability, and sustainability of Wisconsin's electric energy supply.

In the past SEA dated February 2007, the Commission listed four general areas of concern that it would focus on as it moved forward with strategic initiatives. These were:

Environmentally Sustainable Energy Alternatives

The Commission's subsequent involvement in the Governor's Task Force on Global Warming (GWTF), which released its Final Report in July 2008, has helped focus the main issues and goals related to the important issues regarding the environment and sound energy policy. The Commission has been implementing many of the GWTF recommendations.

Accountability in the Regional Wholesale Market

The Commission's efforts and involvement with the Midwest Independent Transmission System Operator, Inc. (MISO), including emphasis on performance and accountability, continues on an ongoing basis.

Improved Planning Process

The inclusion of expanded sections in this draft SEA regarding generation and transmission planning will facilitate added scrutiny needed regarding energy planning, especially for those issues related to the environment and the availability of sustainable energy alternatives.

Utility Workforce Planning

This issue has been followed by the Commission in recent rate proceedings and will continue to be monitored in order to maintain safe and reliable electric service statewide.

MOVING FORWARD

While the Commission is required to prepare this technical document for comments by parties involved in the electric industry, it also intends that the SEA be available to the general public having an interest in reliable, reasonably priced electric energy. To assist the general public, definitions of key terms used within the electric industry are included in this report.

The Commission is required to hold a public hearing before issuing a final SEA. A copy of the notice providing information on the hearing is included with this mailing, and is available for review on the Commission's website http://psc.wi.gov.

The Commission must make an environmental assessment on the draft SEA before the final report is issued. It will be available on the Commission's website at least 30 days prior to the public hearings.

Written comments and comments presented at the public hearing will be used to prepare the final SEA. The Commission encourages all interested persons to comment on the content of this report during the 90-day comment period, which begins with the mailing of this draft SEA. Please address your comments to:

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Questions regarding the process or requests for additional copies of the draft SEA should be directed to Christine Swailes, at (608) 266-8776. Questions from the media and the legislature may be directed to the Commission's Director of Governmental and Public Affairs, Timothy Le Monds, at (608) 266-9600.

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STRATEGIC ENERGY ASSESSMENT REPORT

2008-2014 Electricity Issues

STUDY SCOPE

The Public Service Commission of Wisconsin (Commission or PSC) is required to prepare a biennial Strategic Energy Assessment Report (SEA) that evaluates the adequacy and reliability of Wisconsin's current and future electrical supply.

The SEA intends to identify and describe:

- All large electric generating facilities for which an electric utility or merchant plant developer plans to commence construction within seven years.
- All high-voltage transmission lines for which an electric utility plans to commence construction within seven years.
- Any plans for assuring that there is an adequate ability to transfer electric power into or out of eastern Wisconsin, and the state as a whole, in a reliable manner.
- The projected demand for electric energy and the basis for determining the projected demand.
- Activities to discourage inefficient and excessive power use.
- Existing and planned generation facilities that use renewable energy sources.

The SEA is required by statute to assess:

- The adequacy and reliability of purchased generation capacity and energy to serve the needs of the public.
- The extent to which the regional bulk-power market is contributing to the adequacy and reliability of the state's electrical supply.

- The extent to which effective competition is contributing to a reliable, low-cost, and environmentally sound source of electricity for the public.

- Whether sufficient electric capacity and energy will be available to the public at a reasonable price.

The SEA must also consider the public interest in economic development, public health and safety, protection of the environment, and diversification of sources of energy supplies.

STUDY METHODOLOGY AND LIMITATION

Under statutory and administrative code requirements, every electricity provider and transmission owner must file specified historic and forecasted information. The draft SEA must be distributed to interested parties for comments. Subsequent to hearings and receipt of written comments, the final SEA is issued. In addition, an Environmental Assessment, which includes a discussion of generic issues and environmental impacts, will be issued in connection with the SEA.

This fifth SEA covers the years 2008 through 2014. During the past year, ten large Wisconsin-based investor-owned utilities, cooperatives, municipal electric companies, and other electricity and transmission providers submitted historic information regarding statewide demand, generation, out-of-state sales and purchases, transmission capacity, and energy efficiency efforts. In addition, these entities provided forecasted information through 2014. The Commission also recently requested utilities to provide information related to CO_2 emissions. Responses will be incorporated into this SEA's final report.

The SEA is an informational study that provides the public and stakeholders with relevant trends, facts and issues affecting the state's electric industry. The SEA is not a prescriptive report, meaning that the ideas, facts, projects, and policy discussions contained in this report have not been approved for implementation or construction by the Commission. State law precludes such action, specifically Wis. Stat. § 196.491(3)(dm). Should a specific topic warrant further attention with the intent of Commission action, the Commission must take additional steps as authorized by law.

OTHER STATE INITIATIVES

The GWTF was created by Governor Jim Doyle pursuant to Executive Order 191. The duties of the GWTF pursuant to the Executive Order are as follows:

- Present viable, actionable policy recommendations to the governor to reduce greenhouse gas emissions in Wisconsin and make Wisconsin a leader in implementation of global warming solutions

- Advise the governor on ongoing opportunities to address global warming locally while growing our state's economy, creating new jobs, and utilizing an appropriate mix of fuels and technologies in Wisconsin's energy and transportation portfolios

- Identify specific short-term and long-term goals for reductions in greenhouse gas emissions in Wisconsin that are, at a minimum, consistent with Wisconsin's proportionate share of the reductions that are needed to occur worldwide to minimize the impacts of global warming

The Final Report of the GWTF, approved in July 2008, discusses several concerns and makes recommendations on the following key issues:

- Enhanced Energy Efficiency Programs
- Policy Changes Recommended in Utility Ratemaking
  Aligning Public and Private Interests for Energy Conservation and Efficiency
  Improved and Innovative Rate Design
  Demand Response and Load Management
- Residential and Commercial Energy Efficient and Green Building Codes
- State Government as Leader
- Energy Efficiency and Safety through Lighting for Wisconsin Rental Properties
- Comprehensive Initiative to Support Voluntary Long-Term Greenhouse Gas Emissions Reductions
- Great Lakes Wind Study
- Wisconsin Geologic Carbon Sequestration Study
- Wind Siting Reform

The Final Report of the GWTF sets forth recommendations that focus on supporting individual, community and business early action, advances Wisconsin's strong leadership position on energy efficiency and conservation by moving the state's goals and programs to an even higher level, and initiates several studies and takes other actions necessary to advance our understanding of key issues related to increasing the state's renewable energy resources and otherwise reducing the carbon emissions associated with electric generation.

Executive Summary

DEMAND AND SUPPLY OF ELECTRICITY

- The overall trend in peak demand growth is estimated by the state's utilities to be approximately 2.10 percent per year through 2014. This represents incremental demand increases roughly equivalent to a major power plant of about 500 megawatts (MW) every two years.

- New generation will reduce Wisconsin's reliance on the currently congested transmission grid connections to Illinois.

- Generation ownership has changed. Independent power producers have been active in developing wind projects in Wisconsin. Generation planning shows no new baseload generation is needed during this SEA planning period on a statewide basis.

- Transmission planning may show more EHV is needed in order to bring wind generation to Wisconsin.

- Greenhouse gas emissions need addressing due to climate change policy expectations.

MARKET ANALYSIS AND PLANNING RESERVE MARGIN FORECASTS

- It is expected that the current and ongoing transmission system expansion and improvements will greatly enhance the ability to move electricity into and within Wisconsin by 2010.

- Significant approved new generation coming online is expected to keep planning reserve margins near or above 19 percent through 2012. As of right now, based on already approved payments the planning reserve margin for 2014 is expected to be nearly 12 percent. This number is expected to increase as more energy efficiency and generation is proposed

- The market for purchased generation capacity and energy continues to evolve.

- The Commission will continue to work on the issues associated with balancing environmental protection with reliable and affordable electric energy.

RATES

- Fuel prices and purchased power cost increases, as well as construction costs for generation and transmission facilities, are the significant drivers of recent rate increases.

- Rate increases can be mitigated somewhat with energy conservation, innovative utility financing related to environmental trust fund programs, and other new rate options.

ENERGY EFFICIENCY AND RENEWABLE RESOURCES

- 2005 Wisconsin Act 141 was recently enacted and will substantially revise the funding and structure of energy efficiency and renewable resource programs in Wisconsin. The legislation is based on the recommendations of the Governor's Task Force on Energy Efficiency and Renewables.

ENVIRONMENTAL ISSUES

- The importance of energy efficiency, conservation, and load control to reduce Wisconsin's energy costs and environmental impacts is shown in the findings of the GWTF, as well as analysis in this draft SEA report.

GLOBAL WARMING TASKFORCE RECOMMENDATIONS

- The GWTF recommends policies to aggressively promote much greater energy conservation and efficiency.

NEXT STEPS

- The Commission stands ready to assist the governor and the legislature in doing its part to provide independent technical assessments as Wisconsin moves forward with changing energy use.

Electric Demand and Supply Conditions in Wisconsin

An electricity provider is defined for SEA purposes in Wisconsin Administrative Code as any entity that owns, operates, manages, or controls or who expects to own, operate, manage, or control electric generation greater than 5 megawatts (MW) in Wisconsin. For simplicity sake, Figure 1 shows generators greater than 10 MW. Electricity providers also include those entities providing retail electric service or who self-generate electricity for internal use with any excess sold to a public utility. Major retail electricity providers and/or transmission owners that submitted demand and supply data for this SEA include: American Transmission Company LLC (ATC), Madison Gas and Electric Company (MGE), Manitowoc Public Utility (MPU), Northern States Power—Wisconsin (NSPW) (d/b/a Xcel Energy, Inc. (Xcel)), Superior Water, Light and Power Company (SWL&P), Wisconsin Electric Power Company (WEPCO) (d/b/a We Energies), Wisconsin Power and Light Company (WP&L) (d/b/a Alliant Energy), and Wisconsin Public Service Corporation (WPSC).

These major retail providers were required to include supply and demand data for any wholesale requirements that they have under contract. This action streamlined data reporting and reflected current market activities. Demand and supply data were also provided by Dairyland Power Cooperative (DPC) and Wisconsin Public Power, Inc. (WPPI) on behalf of their member cooperatives and municipal utilities.

Figure 1 Map of Major Electric Generation Plants in Wisconsin

Table 1 shows the aggregated responses of the entities providing data for this draft SEA. The Commission requires providers to maintain 18 percent planning reserve margins. Data for later years should be considered preliminary, because of the longer-term outlook and the very nature of contracting for supply arrangements.

Table 1 Aggregated Responses of Entities Providing Data for this Draft SEA

Line		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
		Historical Actual System Values			*Forecasted Planning Values*						
	Summer Peak Electric Demand (MW)										
	Date of Peak Load			**31-Jul**							
	Date of Peak Load	**9-Aug**	**31-Jul**	**1-Aug**							
1	Peak Load Data & Forecast (non-coincident)	14,395	14,941	14,462	15,429	15,732	15,975	16,296	16,604	16,874	17,155
2	Direct Load Control Program	-37	-61	-49	-171	-171	-173	-176	-179	-185	-186
3	Interruptible Load	-315	-220	-187	-685	-679	-682	-705	-710	-717	-726
4	Capacity Sales Including Reserves	770	732	752	646	706	646	580	640	697	753
5	Capacity Purchases Including Reserves	-719	-725	-656	-611	-708	-575	-533	-564	-595	-626
6	Miscellaneous Demand Factors	-570	-553	-555	-588	-590	-592	-590	-590	-526	-527
7											
8	**Adjusted Electric Demand**	**13,524**	**14,114**	**13,767**	**14,020**	**14,290**	**14,599**	**14,872**	**15,201**	**15,548**	**15,843**
	Electric Power Supply (MW)										
9	Owned Generating Capacity, Used For Wisconsin Load	12,356	12,781	12,824	11,975	12,914	13,287	13,928	14,584	14,828	15,431
10	Merchant Power Plant Capacity Under Contract, Used For Wisconsin Load	3,157	3,790	3,518	4,088	3,505	3,507	3,481	3,212	2,492	1,921
12	New Owned or Leased Capacity Additions	664	60	0	954	309	639	619	300	595	353
17	Net Purchases Without Reserves	543	578	286	271	232	258	294	326	255	254
18	Miscellaneous Supply Factors	-302	-214	-234	-289	-224	-236	-201	-290	-257	-240
19											
20	**Electric Power Supply**	**16,418**	**16,995**	**16,394**	**16,999**	**16,736**	**17,455**	**18,121**	**18,132**	**17,913**	**17,719**
	Reserve Data										
21	Reserve Margin	21.4%	20.4%	19.1%							
22	Planning Reserve Margin				21.2%	17.1%	19.6%	21.8%	19.3%	15.2%	11.8%
	Transmission Data - Firm Interface Capacity Counted for Reserves (MW)										
25	Resources Utilizing PJM/WUMS-MISO Interface	925	890	790	615	435	435	435	235	85	85

UTILITIES' PERSPECTIVE—PEAK DEMAND AND SUPPLY

Demand

The Commission compiled substantial information on peak electric demand and energy use for this report. Demand is a measure of instantaneous use measured in MW. Energy is a measure of the volume of electricity used measured in megawatt hours (MWh). Demand for electricity fluctuates both throughout the day and throughout the year. In any day there are peak hours of demand. In the summer the demand usually has one peak in the afternoon hours. In the winter it is common to have a morning and an evening peak. Over the course of a year demand for electricity is higher in the summer, lowest in the spring and autumn "shoulder" months, and a smaller peak occurs in the winter. Table 2 shows historic monthly peaks since 1997 and forecasted monthly peaks.

Table 2 Assessment of Electric Demand and Supply Conditions, Monthly Non-Coincident Peak Demands, MW

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
						Historical						
1997	9,948	9,386	9,132	8,833	8,518	11,025	11,343	10,265	9,866	9,657	9,598	9,912
1998	10,077	9,326	9,334	8,674	10,286	11,482	12,094	11,411	9,867	9,274	9,394	10,487
1999	10,492	9,531	9,540	8,850	9,108	11,554	13,120	11,331	11,402	9,167	9,953	10,881
2000	10,245	10,004	9,367	9,125	9,986	10,924	11,727	12,726	11,778	9,559	10,082	10,937
2001	10,300	10,032	9,722	9,179	9,742	11,800	13,575	13,870	10,898	9,684	9,805	10,268
2002	10,286	9,965	10,111	9,924	10,381	12,782	13,518	13,454	13,211	10,445	10,080	10,857
2003	10,739	10,498	10,291	9,602	9,048	12,725	13,319	13,694	11,937	10,136	10,450	11,302
2004	10,924	10,384	10,091	9,400	10,273	12,486	12,958	12,437	12,161	9,902	10,557	11,478
2005	11,127	10,678	10,433	9,610	10,000	14,020	13,832	14,323	13,224	11,912	10,833	11,581
2006	10,572	10,475	10,127	9,501	11,421	12,455	14,895	14,400	10,959	10,245	10,834	11,478
2007	10,972	11,233	10,513	9,769	11,306	13,565	14,052	14,783	12,934	10,754	11,052	11,747
						Forecasted						
2008	11,586	11,100	10,918	10,261	11,222	14,062	15,384	15,328	13,237	11,013	11,282	12,021
2009	11,857	11,464	11,156	10,476	11,469	14,349	15,690	15,621	13,528	11,207	11,471	12,201
2010	12,013	11,628	11,346	10,649	11,681	14,573	15,933	15,862	13,731	11,352	11,607	12,344
2011	12,305	11,899	11,556	10,866	12,027	14,962	16,250	16,226	14,081	11,535	11,839	12,651
2012	12,499	12,086	11,747	11,046	12,238	15,232	16,548	16,528	14,305	11,715	12,021	12,833
2013	12,670	12,253	11,922	11,207	12,424	15,483	16,827	16,788	14,555	11,880	12,183	13,022
2014	12,853	12,436	12,104	11,380	12,621	15,746	17,115	17,063	14,799	12,044	12,353	13,209

Using the projections provided by the entities submitting data for this SEA, this pattern of winter and summer peaks is expected to continue into the future. While actual demand will remain dependent upon weather, the overall statewide trend is expected to show continued growth in peak demand, estimated by the state's utilities combined to be approximately 2.10 percent per year through 2014.[1] Currently, the Commission is investigating planning reserve margins. Specifically, what is the adequate planning reserve margin for Wisconsin in today's energy marketplace?

On June 22, 2007, the Commission held a technical conference, attended by the Commissioners, where stakeholders offered comments and recommendations regarding generation and transmission planning in Wisconsin. Comments were varied, and included:

- Efficient resource planning requires the consideration and integration of all resource options to identify least-cost alternatives that can be expected to achieve a broad range of desired objectives including environmental value.
- The process should be collaborative and transparent, and facilitate conversations between states.
- Planning should be regional.
- Planning should integrate baseload generation and renewables.
- The Commission should participate in the MISO transmission planning process.

[1] As part of this SEA, Commission staff has not prepared its own forecast for peak demand. In a later section, under generation planning, Commission staff does utilize energy and demand forecasts with somewhat lower growth rates than the combined values provided by the state's utilities.

- The Certificate of Authority/Certificate of Public Convenience and Necessity process requires integration of energy conservation, generation including renewables, and transmission options.
- The Commission should revisit the drivers behind potential price increases and identify optimal balance between meeting policy objectives, environmental compliance, and rates.
- The Commission should adopt a staged approach to resource planning and implementation by forecasting electricity needs, assessing energy efficiency demand response and supply resources, and integrating all resources.

PROGRAMS TO CONTROL PEAK ELECTRIC DEMAND

The state's utilities have two forms of peak load management, direct load control and interruptible load. Peak load management is removing load from the system at times when utility resources for generation are not able to meet customer demand for energy. These programs were traditionally expected to be used primarily in the summer months, usually on very hot days when demand for electricity is at its highest. In recent years, under certain circumstances, when the winter peak demand for electricity outpaced available generation, these programs have been used to assure a balance between demand and available supply.

Direct load management gives the utilities the ability to take off the system electric demand such as residential air conditioners. When a utility implements direct load control, affected customers who volunteered to participate in the program receive a credit on their utility bill. Prior SEAs and Table 1 show that direct load control has been used very sparingly from 2005 through 2007; between 37 and 61 MW of direct load control were called upon. As shown in Table 2, the MW of direct load control available to utilities is much greater than what was called upon.

The second form of load management is the use of interruptible load for industrial customers. An industrial customer choosing to select an interruptible load tariff receives a lower electric energy rate (cents per kilowatt hour (kWh)) by agreeing that load may be interrupted during periods of peak demand on the system. A utility will notify an industrial customer on an interruptible load tariff that its load will be taken off the system at a specific time. Again, the actual MW of load that are interrupted in a given year is less than the MW of load that are covered by interruptible tariffs. In any given year, the need to utilize this form of load control will depend upon generation supply that is available on the days when peak demand happens or when available generation is tight due to planned or unexpected (forced) outages. By 2014 interruptible load is expected to be approximately 4 percent of projected electric power supply.

Table 3 Available Amounts of Programs and Tariffs to Control Peak Load, MW

Year	Direct Load Control (MW)	Interruptible Load (MW)
	Historical	
1997	169	677
1998	162	794
1999	173	773
2000	169	664
2001	185	637
2002	200	583
2003	186	554
2004	193	628
2005	225	693
2006	178	807
2007	175	772
	Forecasted	
2008	171	685
2009	171	679
2010	173	682
2011	176	705
2012	179	710
2013	185	717
2014	186	726

PEAK SUPPLY CONDITIONS: GENERATION AND TRANSMISSION

As noted in Table 4, the planning reserve margin for 2008 is expected to be 21.2 percent. Even with the rather robust growth in peak summer demand indicated by the utilities of approximately 2.10 percent per year through 2014, the significant approved additional new generation coming online through 2010 is expected to keep planning reserve margins near or above 18 percent through 2012. Generation adequacy has been successfully addressed. Figure 1 is a map of existing and planned major electric generation facilities for Wisconsin.

Table 4 Forecast Planning Reserve Margins from SEA

Planning Year	Final SEA2000	Final SEA2002	Final SEA2004	Final SEA2006	Draft SEA 2008
2001	17.95%				
2002	17.44%				
2003		19.07%			
2004		20.86%	18.30%		
2005			17.43%		
2006			14.97%		
2007			16.13%	18.20%	
2008			12.80%	18.90%	21.2%
2009			10.00%	16.40%	17.1%
2010			11.00%	17.50%	19.6%
2011				17.20%	21.8%
2012				17.40%	19.3%
2013					15.2%
2014					11.8%

Note: The SEA was expanded to cover seven years of forecast data in 2004; prior SEAs only examined two years.

Table 4 illustrates planning reserve margins over time. Table A-1, shown in the appendix of this report, shows new generation facilities and upgrades expected to be in operation or under construction by 2014. It does not include the utilities' listed retirements, as the timing of these is more uncertain. Nor does it include 3-5 MW de-ratings of coal units due to installation of additional air pollutant controls (the two Pleasant Prairie units would each be de-rated by 8 MW). Table A-1 includes three Commission-approved baseload serving units, an intermediate load serving unit, and three wind projects. Since the last such SEA listing, three combined-cycle units, a cogeneration facility, and combustion turbines are now operational. The Commission is currently reviewing a proposed baseload unit and an out-of-state wind project. Therefore, the list in Table A-1 must be viewed for what it is: utility requests for new generation, and not necessarily projects approved by the Commission. Those projects that have been approved are noted, however.

NEW GENERATION

Wisconsin is in a multi-year expansion period for electric generation that will expand in-state generation capacity by over 3,000 MW through 2014. Over the past three years, from 2005 through 2007, over 1,600 MW of additional, new generation capacity has been brought into service.

Looking forward, new facilities will include three new, large coal-fired units with over 1,700 MW of capacity, the first new, super-efficient, coal-fired baseload plants in Wisconsin since the early 1980s. Almost 750 MW of new wind powered generation are expected to become part of the Wisconsin generation mix between 2008 and 2014, over 300 MW of new wind projects have been approved at wind farms in Wisconsin. Other wind projects in Iowa and Minnesota will further diversify the location of wind resources for the benefit of Wisconsin ratepayers. An expected 575 MW of combined-cycle capacity and 55 MW of combustion turbine capacity is projected to be fired by natural gas. A 90 MW generation addition from an upgrade of a nuclear powered plant, now all merchant owned, is also expected. Figure 2 illustrates new utility-owned or leased generation capacity for this SEA reporting period. Figure 3 shows the MW capacity by fuel type as of July 2007. Figure 4 shows the MWs of energy produced by fuel type for 2006.

Figure 2 New Utility-Owned or Leased Generation Capacity, 2008-2014

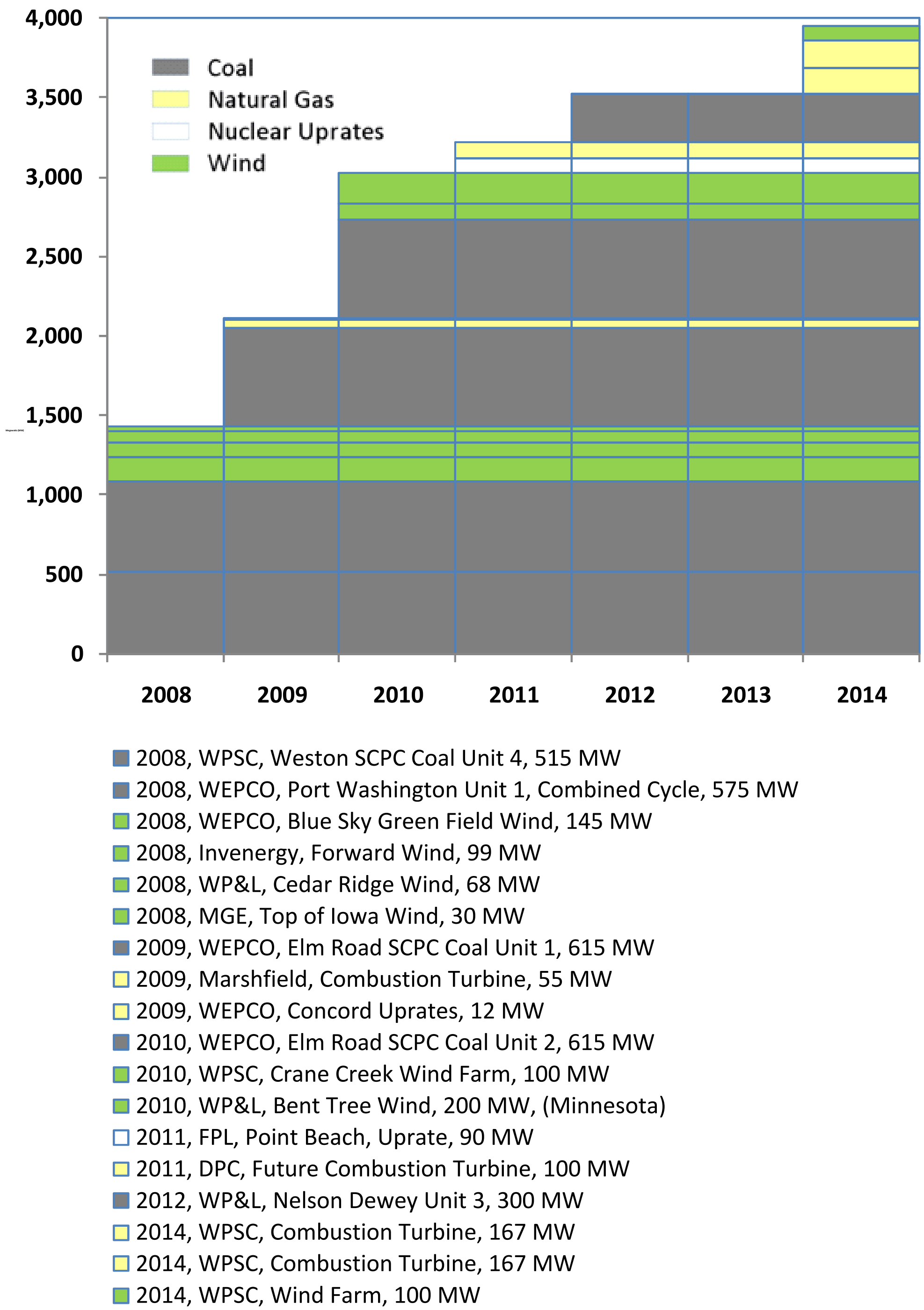


Figure 3 Capacity by Fuel Type as of July 2007 (MW)

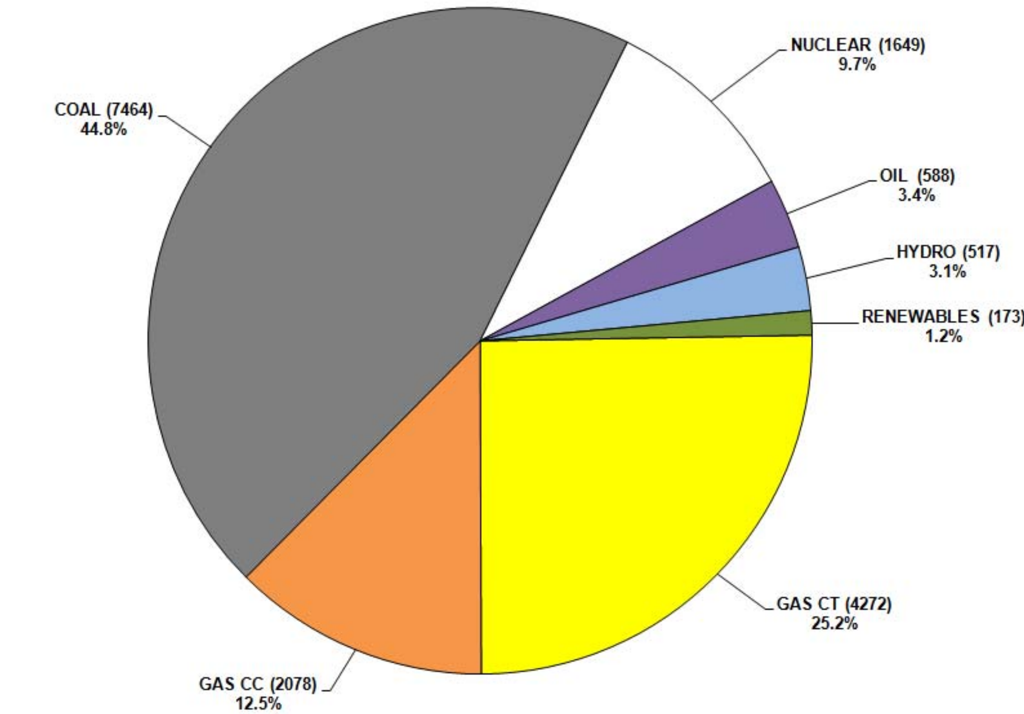
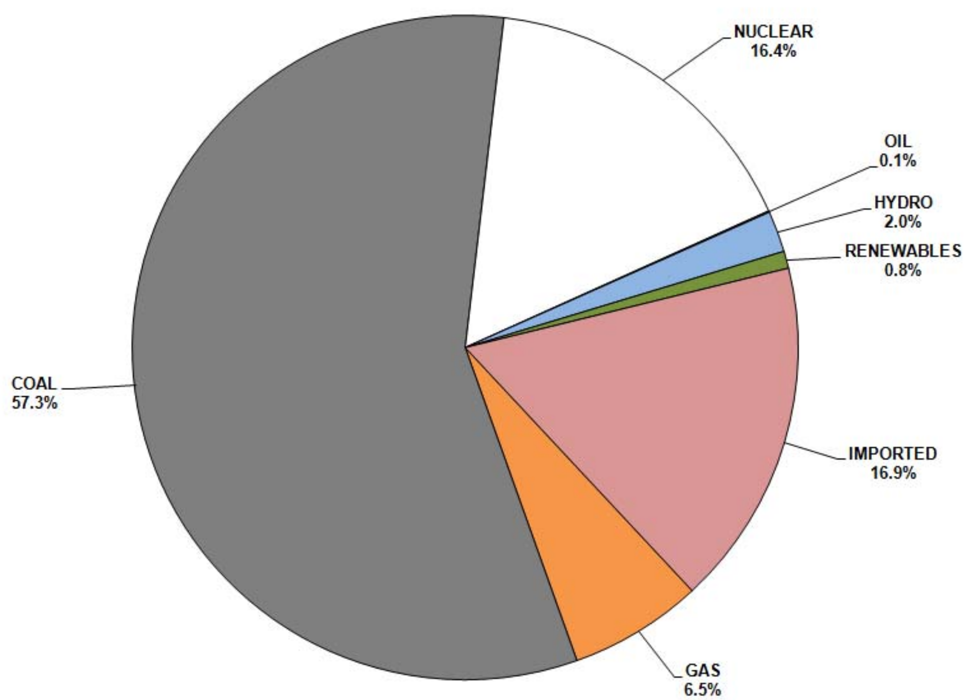


Figure 4 Actual Generation by Fuel for 2006 (MWh)



COMMISSION STAFF ANALYSIS—GENERATION PLANNING AND MODELING

The SEA is not prescriptive and its purpose is to identify issues facing Wisconsin's energy future and explore opportunities for meeting future energy challenges. To better understand these future challenges for this report, Commission staff utilized the Electric Generation and Expansion Analysis System (EGEAS) for modeling similar to how planning studies have been utilized by Wisconsin utilities for 20-plus years.

EGEAS selects the optimal combination of generation resources to be constructed in the future, based on forecasted demand and energy, cost of construction for new generation, fuel costs, variable operations and maintenance (O&M) expenses, and fixed O&M expenses for all generating resources—existing, committed, and new generating units. The model can also be forced to pick certain units in any given year. This feature is used to place wind units to meet the requirements of Wisconsin's renewable portfolio standard (RPS). The new generating units that the model could choose to meet demand include generic coal-fired plants, generic combined-cycle gas-fired plants and combustion turbines, generic wind turbines, and single-year energy purchases.

The analysis summarized here performs a study of the entire ATC footprint, which accounts for 85 percent of Wisconsin's energy needs. The aggregate analysis eliminates some of the lumpiness seen with bringing large generating units on line for individual utilities. EGEAS identifies a need, but does not determine where a power plant should be built or where power lines are routed.

The EGEAS data set used by Commission staff was created by combining available data from the ATC utilities (WEPCO, WPSC, WP&L, MGE and WPPI). One of the reasons this footprint was chosen is that 2006 hourly load data was available for the ATC footprint.

Additionally, while NSPW imports the bulk of the energy necessary to meet its load, this import requirement is partially offset by the export from DPC based on reported 2006 data. The additional energy needs of a Wisconsin footprint (including NSPW and DPC) could be approximately modeled in a future SEA proceeding, if so desired. The EGEAS planning period is 2006-2035, with a 30-year extension period.

In today's world of Regional Transmission Organizations (RTO), electric utilities have the option of locating their generation facilities outside of their service territory and transporting the power via the RTO's transmission facilities. This may or may not be more cost-effective than locating a generating facility in a utility's service territory. One needs to compare the fuel transportation cost savings (mine mouth coal) or higher capacity factor (wind) of building that generation in locations farther away with any additional transmission infrastructure or locational marginal pricing (LMP) costs of locating generation within the electric utility's service territory. Issues associated with transmission are discussed later in this draft SEA.

Specific modeling assumptions used by Commission staff are discussed in the following sections.

Emission Monetization and Control

For all EGEAS modeling scenarios used for this SEA analysis, SO_2 ($400 per ton), NO_x ($2,000 per ton) and mercury ($35,000 per pound) are monetized. The monetization of CO_2 ($22.66 per ton) is performed as a sensitivity in one modeling scenario. According to the CarbonPoint.com web site, the cost of carbon credits on the European market recently has ranged from US$28 to $31 (€$18.50 to $21). All monetization costs are in 2006 dollars and are escalated on an annual basis. There are numerous estimates for monetizing CO_2, some which are lower than $22 and some which are higher.

Additionally, Commission staff assumed that several of the existing coal units will have emission control equipment installed within the SEA period (2007 through 2014). This was modeled by initially assuming the units will operate as they currently do (without emission control equipment). The units are then retired after the last year they are assumed to operate without the emission control equipment. The following year they are forced back into the model with the operating characteristics and costs of the original unit, with modifications to reflect the installation of the emission control equipment. The units staff assumed would install emission control equipment and the year of assumed installation for modeling in EGEAS are shown in Table A-04. Table A-04 shows staff's assumption for the installation of emission control equipment. Some of these decisions still need to be reviewed by the Commission, and these assumptions should not be viewed as Commission determinations. Table 5 summarizes known information about possible emission control equipment construction in the future.

Table 5 Major Emission Control Projects* at Wisconsin Investor Owned Utilities' Power Plants

Unit Name	Utility Owner	Status	Type of Emission Control**
Pleasant Prairie 1	WE	Complete	SCR/FGD
Pleasant Prairie 2	WE	Complete	SCR/FGD
Oak Creek 5	WE	Complete	SCR/FGD
Oak Creek 6	WE	Complete	SCR/FGD
Oak Creek 7	WE	Complete	SCR/FGD
Oak Creek 8	WE	Complete	SCR/FGD
Columbia 1	WP&L/WPSC/MGE	Not Filed	FGD
Columbia 2	WP&L/WPSC/MGE	Not Filed	FGD
Edgewater 4	WP&L/WPSC	Not Filed	FGD
Edgewater 5	WP&L/WE	Not Filed	
Nelson Dewey 1	WP&L	Pending	FGD
Nelson Dewey 2	WP&L	Pending	FGD
Weston 3	WPSC	Pending	FGD

Major emission control projects only include projects over $25 million. Table does not include combustion control projects for NO_X. Does not include activated carbon control projects for mercury.
** Selective catalytic reduction (SCR); flue gas desulfurization (FGD)

Unit Retirements Assumed by Commission Staff

All of the coal units set out in Table 3 were assumed to continue operation through 2035. In all EGEAS modeling scenarios, Commission staff assumed the following units were retired in the year shown.

2008 – Oak Creek 9
2009 – Point Beach 5
2011 – Blount 3, 4 and 5
2012 – Pulliam 3 and 4, Blackhawk 3 and 4, Rock River 3, and Presque Isle 1 and 2
2013 – Rock River 4
2014 – Blount 6 and 7, Menasha 3, and Rock River 1
2015 – Rock River 2

Point Beach Nuclear Power Plant Units 1 and 2 have received a 20-year license extension by the Nuclear Regulatory Commission (NRC) in December of 2005 and are modeled as operating until 2030 (Unit 1) and 2033 (Unit 2). Kewaunee Nuclear Power Plant was assumed to be granted a 20-year license extension by NRC and operate to the benefit of Wisconsin through 2033.

Anticipated Growth Rates

Historically, energy growth is usually the largest variable in determining need for new generation. The Commission staff EGEAS analysis for the 2008 SEA examined the ATC peak and energy data for 2003 through 2006. The average energy growth for those years was approximately 1.0 percent per year. The peak growth was slightly more than energy. This energy use is net of demand-side management (DSM) savings. The energy needs for a specific utility will likely be different from the projected aggregate growth for the ATC footprint.

In the staff EGEAS analysis, energy use is assumed to increase at 1.0 percent per year. (In the data submitted by the utilities, the expected increase is approximately 1.8 percent per year.) Peak demand is assumed to increase at 1.5 percent per year from 2006 through 2025. As indicated earlier, the utilities' projection showed on a statewide basis growth of about 2.1 percent per year. From 2026 through 2035 peak demand is assumed by Commission staff to increase by 1.05 percent. These are conservative growth estimates for this modeling, and reflect aggressive energy efficiency efforts. These estimates are lower than estimated growth compiled from utility forecasts. While the Commission staff forecast is based on historic usage, higher than expected economic growth or the use of new technologies such as plug-in hybrid electric vehicles (PHEV), could result in an actual future growth rate closer to that forecast by the utilities. The load used by Commission staff for 2006 is 65,983.2 gigawatt hours (GWh). By the end of the SEA period (2014), the load is estimated to be 71,450.4 GWh using the growth percentages set out above.

If the actual energy and peak demand growth exceed that projected by Commission staff, the actual new plant needs may vary significantly from that reflected in Commission staff's EGEAS model results.

Future Estimated Fuel Prices

Just as energy growth is the largest variable to determine the need for new facilities, fuel prices are the largest variable in determining what the overall production cost will be. Higher fuel prices also make it more economical to install newer, more efficient units.

For Commission staff's EGEAS modeling in this draft SEA, the cost of coal is estimated to be $1.27 (in 2007 dollars) per million British thermal units (MBtu) and is escalated on an annual basis so that the annual cost of coal is the average of the estimates supplied by the utilities. The cost of natural gas is estimated to be $9.27 (in 2007 dollars) per MBtu and is escalated on an annual basis so that the annual cost of coal is the average of the estimates supplied by the utilities. Fuel costs during 2008 have been dynamic, rising, and volatile. These estimates will be revisited in the final SEA as appropriate.

Generation Options

The costs for generation technologies Commission staff used for EGEAS modeling purposes are shown in Table 6. The prices used for the assessment were based on a review of utility-supplied information. Construction costs for wind, natural gas, and coal electric generating facilities have increased substantially in recent years. Regardless of which type of technology is selected, the total plan cost (in net present value (NPV) 2006 dollars) will be approximately $7 billion, 14 percent more than the same plan using construction costs from two years ago.

Table 6 Estimated Cost of Generation

Technology	Staff Estimated Capital Costs ($/kW)
Combustion Turbine (150 MW)	$695
Combined-Cycle (500 MW)	$875
Pulverized New Coal (500 MW)	$2,965
Wind (200 MW block)	$2,070
Nuclear	$5,600

Note: These cost estimates will be updated in the final SEA report to reflect current estimates.

For the Commission staff's EGEAS modeling, all capital costs were assumed to be capitalized and the costs were levelized or spread equally over the estimated life of the unit. The levelized interest costs were assumed to be 12 percent for all projects except coal which was assumed to be 12.2 percent. The model can also choose a 1-year power purchase option. Each power purchase option is 100 MW and up to four purchases can be made annually.

Nuclear

New nuclear power plants were not allowed as a planning option. Current U.S. Department of Energy (DOE) projections put the opening of the Yucca Mountain repository in the years 2017-2021, which is beyond the current SEA period. Unless the current state moratorium on new nuclear construction is lifted at the legislative level, nuclear generation is not an option given the current projected timing of the opening of the Yucca Mountain repository. However, the NRC has received combined license applications for reactors in Alabama, Georgia, Maryland, Massachusetts, North Carolina, South Carolina, Texas, and Virginia.

Costs, timing of construction, and necessary regulatory approvals are all uncertain at this time. This is an issue that the Commission will continue to monitor.

Integrated Gasification Combined-Cycle

Integrated gasification combined-cycle (IGCC) plants are not a new plant option in Commission staff's EGEAS modeling. Currently, the capital cost of IGCC plants is approximately 10 percent more than a conventional pulverized coal plant. Further, without carbon sequestration, the emissions from an IGCC plant are not significantly less than for a conventional pulverized coal plant. Therefore, if EGEAS does not choose a conventional pulverized coal plant, it will not choose an IGCC plant.

Wind

As shown in Table 4, Commission staff assumed wind capital costs of $2,070 per kW in 2006 with a 2 percent annual escalation rate. The exact cost could be higher or lower. The federal production tax credit is assumed to be extended and is included in the price of all wind generation options included in the EGEAS model. Staff, in general, forced 400 MW of wind generation to be installed per year. This was adequate to meet the requirements of the 10 percent (by 2015) RPS in all modeling scenarios performed by staff, except for the 25 percent renewable generation level by 2025 scenario. To achieve a 25 percent renewable level by 2025 required 600 MW of wind to be installed in each year 2021 through 2025.

Wind was modeled as a non-dispatchable unit using hourly wind profiles. A 20 percent credit to the reserve margin was used for all wind generation. It was assumed that utilities would install wind instead of obtaining fixed price contracts. As an option, the Commission may want to explore fixed price contracts regarding utility-owned wind generation in certain situations.

Demand Side Management

The high DSM EGEAS modeling scenario included an additional $100 million annually of expenditures for energy conservation, in addition to what was assumed in the base model. The DSM programs were modeled as limited energy units. This is consistent with how DSM programs have been modeled by some Wisconsin electric utilities in the past. This dollar amount came from a preliminary recommendation by the GWTF. The $100 million was allocated to the various DSM programs on a percentage basis equal to the percent to total of current DSM spending. The $100 million was assumed to be sufficient to acquire DSM at the current unit cost supplied by Wisconsin electric utilities.

The Renewable Portfolio Standard

Under Wis. Stat. § 196.378, the level of renewable resources should be approximately 10 percent by 2015, on a statewide basis. This RPS requirement is modeled in all EGEAS scenarios modeled by Commission staff. In order to model this RPS requirement, staff has assumed that the RPS is met by wind generation. The amount of wind required is over 2,000 MW. If other sources of renewable energy are utilized, they are likely to be more expensive than wind, at least in the short term. Without the production tax credit, wind costs increase substantially.

The RPS standard does not require that the renewable generation facility be located in Wisconsin. In recent years, wind facilities supplying renewable power to Wisconsin electric utilities have been located in both Wisconsin and Iowa. The hourly wind profiles used by Commission staff in its EGEAS modeling reflect both Wisconsin and Iowa wind regimes.

Commission Staff EGEAS Scenarios

The transmission section of this draft SEA discusses the Midwest Independent Transmission System Operator, Inc. (MISO) Transmission Expansion Plan (MTEP). MTEP08 contained four scenarios: the base scenario; a carbon monetization scenario; a 20 percent renewable scenario; and a limited supply of natural gas scenario. It is anticipated that MTEP09 will include additional scenarios such as a 30 percent renewable scenario and a regulation scenario in which only clean coal[2] is allowed to be added after 2013.

Commission staff modeled EGEAS scenarios with the intent that they approximately mirror the MTEP scenarios. Staff's EGEAS scenarios include a base scenario, a CO_2 monetization scenario, a 25 percent renewable scenario, a high DSM scenario, and a high (plus 10 percent) and low (minus 10 percent) fossil fuel cost scenario (instead of a limited supply of natural gas scenario). Table 7 sets out the results of these modeling scenarios. The plan cost is the net present value cost for the entire plan (2006-2035), including extension period.

Table 7 Summary of Modeling Results

	Base Model		25% Renewable Model		Monetize CO_2 Model	
Year	Plants Suggested by EGEAS Modeling *	Total Cost of Base Model **	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **
2008	Wind (1)	$54.5 billion	Wind (1)	$6.1 billion	Wind (1)	$20.2 billion
2009	Wind (2)		Wind (2)		Wind (2)	
2010	Wind (2)		Wind (2)		Wind (2)	
2011	Wind (2)		Wind (2)		Wind (2)	
2012			Wind (2)			
2013			Wind (2)			
2014			Wind (4)			
2015	Wind (2)		Wind (2)		Wind (2)	
2016	CC (1)		Wind (2)		CC (1)	
2017	CT (1)		Wind (2)		CT (1)	

	High DSM Model		High Fuel Cost Model		Low Fuel Cost Model	
Year	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **
2008	Wind (1)	$-700 million	Wind (1)	$1.9 billion	Wind (1)	$-2.0 billion
2009	Wind (2)		Wind (2)		Wind (2)	
2010	Wind (2)		Wind (2)		Wind (2)	
2011	Wind (2)		Wind (2)		Wind (2)	
2012						
2013						
2014						
2015	Wind (2)		Wind (2)		Wind (2)	
2016			CC (1)		CC (1)	
2017			CT (1)		CT (1)	

* ( ) indicates number of units installed
** Total plan (2006-2035) dollars (NPV 2006)

[2] Clean Coal means coal combustion technologies that allow the burning of coal with reduced air emissions.

Generation Planning Conclusion

Assuming all currently authorized generation is constructed and placed into operation, and electric utilities continue to construct renewable generation in order to meet the requirements of Wis. Stat. § 196.378, Commission staff's EGEAS analysis shows no additional generation for the state as a whole (beyond the renewable generating facilities) is needed in the SEA period (2007-2014). However, the EGEAS modeling results suggest that in the years immediately following the SEA period, additional natural gas electric generating facilities may be needed. This result occurs because the optimization is done on an ATC-footprint basis. Optimization on a specific utility basis could show different results. This is a very important distinction with significant policy implications, because applications for new generation plants that the Commission reviews during construction cases are usually made by an individual utility.

The escalating costs of all electric generation construction[3] leads to the possibility that increased DSM may result in a lower-cost generation plan, depending on the unit cost of DSM. If the cost of additional transmission facilities is considered, the potential for cost-effective DSM options increases. Wind generation will be constructed to comply with RPS standards. The excess energy could be sold into the MISO market and, at a minimum, will give Wisconsin more flexibility with possible power plant retirements.

[3] Limiting greenhouse gas emissions (mainly CO_2) is expensive and may be even more if the cost for CO_2 credits exceeds that anticipated by Commission staff. This is a possibility given the current price of CO_2 credits on the European exchange.

Transmission System Plans, Issues, and Developments

LOCATIONS AND DESCRIPTIONS OF PROPOSED TRANSMISSION PROJECTS IN WISCONSIN

By state statute, this SEA is to report all transmission lines designed to operate at voltages above 100 kV on which transmission providers propose to begin construction before 2014, subject to Commission approval. The transmission owners that provided transmission project information include ATC, DPC, and Xcel. "Construction" means building new lines, rebuilding existing lines, or upgrading existing lines. Building new lines requires new transmission structures and, likely, requires new right-of-way (ROW). Rebuilding or upgrading existing lines may also require new structures or new ROW.

To rebuild a line means to modify or replace an existing line; in other words, to keep it at the same voltage and improve its capacity to carry power through new hardware or design. To upgrade an electric line means to modify or replace an existing line, but at a higher voltage. An upgrade also improves the line's capacity to carry power. Both rebuilding and upgrading may require some (or many) new, taller structures. New ROW may also be needed if the new structures require a wider ROW, or if the line route requires relocation to reduce environmental impacts. Either way, rebuilt or upgraded transmission lines usually need significantly less new ROW than new lines.

The primary reasons for needing additional transmission lines may include one or more of the following:

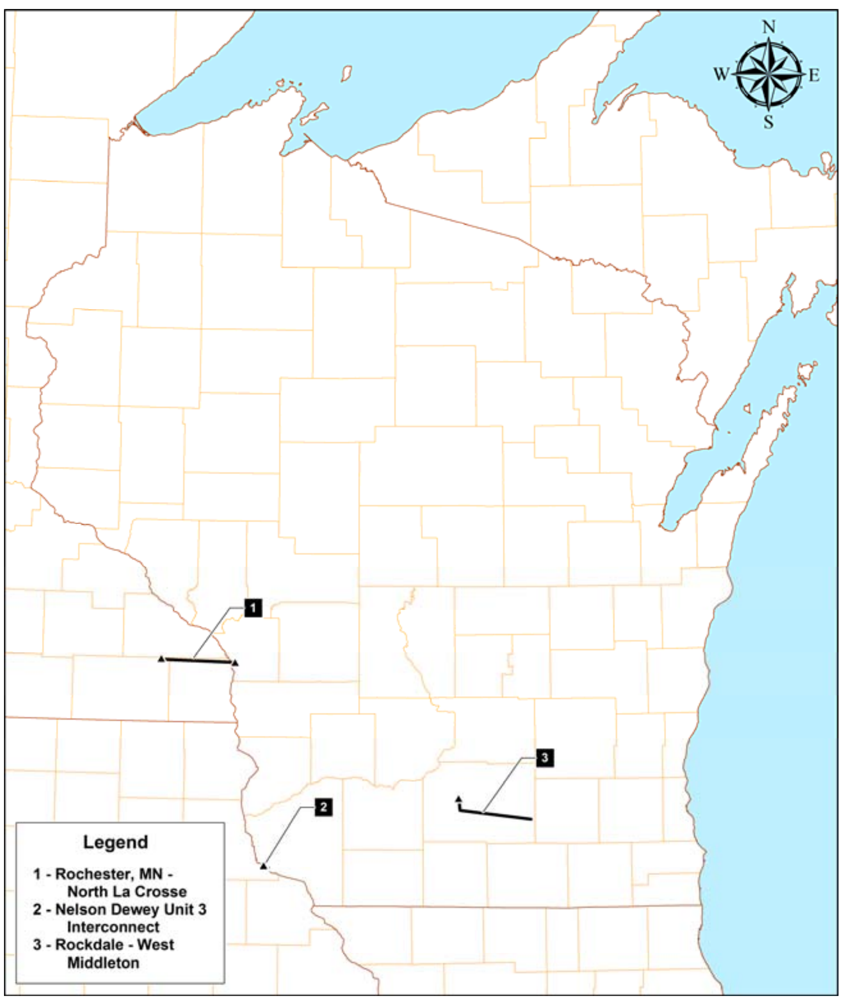
- Growth in an area's electricity use, which often requires new distribution substations and new lines to connect them to the existing transmission system, or needed increased capacity of existing transmission lines;
- Aging of existing facilities that has resulted in reduced reliability due to poor condition;
- Maintenance of system operational security for the loss of any one transmission or generation element;
- Increased power transfer capability or access;
- Generation interconnection agreements and transmission service requirements for proposed (or approved) new power plants; and
- Maintenance of transmission system reliability and performance.

In general, the higher a line's voltage, the more power it can carry. As a consequence, the higher-voltage transmission lines are important in delivering large amounts of power on a regional basis, and the lower-voltage lines primarily deliver power over a more limited area. The ability to deliver power reliably to local substations and the ability to import power from, or export to, other regions, are both important functions in providing adequate, reliable service to customers.

Table A-2 in Appendix A shows new electric transmission lines on which construction is expected to start by 2014 if approved by the Commission. Unlike the generation table, this table does not include any transmission lines already approved by the Commission and under some phase of construction; these would number about 20 projects.

Table A-3 in Appendix A lists proposed high-voltage transmission projects involving new ROW. This table provides further detail for only one proposed transmission line listed in Table A-2. Other lines in Table A-2 are proposed to primarily use existing electric transmission line ROW. Projects with Certificate of Public Convenience and Necessity (CPCN) applications already filed with the Commission are not listed in Table A-3.

Figure 5 Proposed High-Voltage Transmission Line Additions Involving New ROW, on which Construction is Expected to Start Prior to December 31, 2014, if approved by the Commission



TRANSMISSION PLANNING IN THE MIDWEST

Background

The Federal Energy Regulatory Commission (FERC) has asserted jurisdiction over operation of the transmission system in the U.S. because of its use in interstate commerce, and Congress has given FERC authority over transmission system reliability. FERC adopted Order No. 890 in February 2007 reforming the landmark 1996 open access rules in Order Nos. 888 and 889. See Appendix B for the nine planning principles of FERC Order No. 890. The expanded goals of the open-access transmission regulatory framework are to ensure transmission service is provided on a non-discriminatory, just and reasonable basis, as well as to provide for more effective regulation and transparency in the operation of the transmission grid. FERC's final rule on open access includes the following specific intents:

- Increase non-discriminating access to the grid by having consistency in the calculation of Available Transfer Capability methodologies in coordination with the North American Electric Reliability Corporation (NERC).
- Increase the ability of customers to have access to new generation resources by requiring open, transparent and coordinated transmission planning process.
- Increase efficient utilization of transmission by eliminating artificial barriers to the grid.
- Facilitate the use of the grid to obtain clean energy resources, such as wind.
- Strengthen the compliance and enforcement process.

In an important new development, FERC directed all transmission providers to develop a transmission planning process that satisfies nine principles of Order No. 890 and to clearly describe the transmission planning process in a new Attachment K to their Open Access Transmission Tariff. All Attachments K were filed by December 7, 2007. The transmission providers of interest in the Wisconsin area include: MISO, which is the regional grid operator in the upper Midwest spanning the approximate geographic area from Ohio in the east to Montana in the west and as far south as Missouri (see Figure A-04 for a map of RTOs); the Mid-Continent Area Power Pool (MAPP); Xcel; DPC; and ATC. FERC has not ruled on the Order No. 890 filings made by MISO, ATC, Xcel, or DPC as of this writing.

Transmission planning is the most complex of the topics covered in this SEA. This is because transmission planning encompasses numerous overlapping issue areas, and requires the use of sophisticated computer modeling that factors in existing generation and transmission projects as well as new or proposed projects. Transmission planning has many economic, engineering, environmental, and political perspectives that must be considered, such as:

- Should the transmission planning focus on a particular utility, state, region, or sub-region, or the entire country?
- How should transmission planning factor in expected new generation developments?
- Should the transmission system be planned and constructed ahead of new generation developments, or should it lag those generation developments?

- Who should do the transmission planning?
- Should the transmission system be planned and constructed for reliability reasons and the elimination of system congestion, or should the transmission system be planned and constructed for a larger goal of fostering interstate commerce of electricity?
- Who should pay for any new proposed transmission projects? Should the costs be borne by the constructing utility alone, or shared on a regional or zonal basis?
- How can different state policies with respect to resource portfolios be factored in if one state, for instance, relies more on renewable resources than another state?
- How do projects that appear in transmission plans reach fruition? What process is used to approve the assorted projects, and who decides if the projects' costs are to be shared?
- How do policy makers ensure that the transmission system is neither underbuilt nor overbuilt?
- How does transmission planning factor in some states' preferences to more aggressively address environmental factors than other states?
- How does appropriate transmission planning factor in the varying types of providers for transmission service such as stand-alone transmission companies such as ATC and vertically-integrated utilities like Xcel?
- How does transmission planning accommodate the fact that some states have deregulated their electricity sectors more so than others?
- Can transmission system improvements and better generation dispatch in the region act as a substitute for new generation?
- How does increased use of energy efficiency and demand reduction programs affect the need for new transmission projects?
- How does transmission planning factor in new generation facilities when the exact location of this future construction is not known?

Due to this long list of questions and the difficulty in addressing all the issues simultaneously, no single preferred entity or transmission planning process has emerged. Rather, transmission planning is being conducted by different entities on different fronts and in different fashion. The following discussion highlights the forms transmission planning is taking in the area affecting Wisconsin. As part of this SEA, Commission staff has not produced an optimal transmission plan for Wisconsin.

MISO Transmission Planning

At present, MISO is using the following transmission planning principles:

- Make the benefits of a competitive energy market available to customers by providing access to the lowest possible electric energy costs.
- Provide a transmission infrastructure that safeguards local and regional reliability.
- Support local and federal renewable energy objectives by planning for access to all such resources such as wind, biomass, and DSM.

- Create a mechanism to ensure investment implementation occurs in a timely manner.
- Develop a transmission system scenario model and make it available to state and federal energy policy makers to provided context and inform the choices they face.

MISO hypothesizes that the current transmission planning paradigm, based primarily on reliability assessment which minimizes transmission build, leaves value for customers on the table. That is, the answers to the above questions require the total evaluation of all benefits including economic, reliability, and public policy concerns to meet longer-term needs for the next 20 years.

MISO Planning Cycle Approaches

MISO presently uses the following planning cycles when performing transmission system planning whether for a utility, the region of its footprint, or an even larger area beyond its footprint:

- 12-Month
  - Based on five-year NERC Reliability Standards (due to ten-year screens, the focus is on 2013 and 2018 this year).

- Multi-year
  - 10- to 20-year Economic View, which is value-based, including a Joint Coordinated System Plan (JCSP) with surrounding regional transmission providers such as Southwest Power Pool, Tennessee Valley Authority, and PJM.

- 12- to 24-Month
  - Targeted studies to address specific issues such as, congestion, narrowly congested areas, narrowly constrained areas, renewable portfolio standards in the Midwest, as well as queue related and operational studies. One example is the Regional Generation Outlet Study.

- MTEP
  - Annual – A snapshot of currently recommended expansions resulting from all completed planning studies. MTEP also provides information for conceptually planned additions and other exploratory studies.
  - Projects approved in MTEP, depending on the project, may be eligible for cost sharing. That is, a transmission capital project's cost may be borne by utilities outside the zone where the line is being constructed. MISO is presently conducting an MTEP08 Reliability Assessment.

MISO Transmission Planning Examples

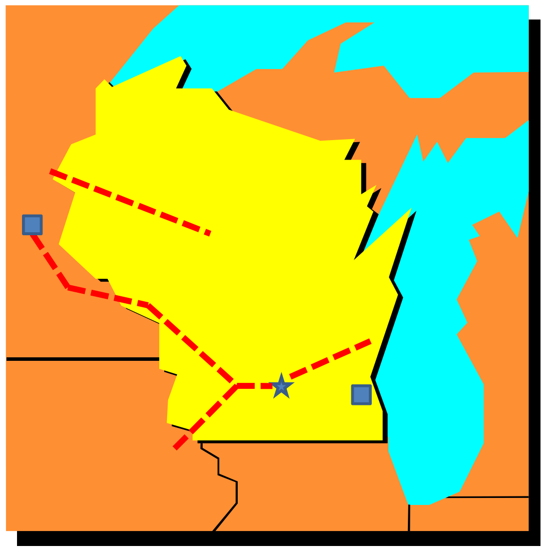
The MISO planning process relies on future scenario analysis that tests the ability of a particular set of transmission elements to provide a reliable system, in a timely manner, with different, possible futures. Reliability is composed of two components: security—the ability to not fail often; and adequacy—the ability to provide service constantly. MISO believes its scenario-based overlay planning architecture is a strategic long-term analysis that factors in the numerous concerns outlined in the questions above.

There are several future scenarios being considered by MISO. Possible sets of transmission lines were placed into load flow and production cost models to test performance for reliability and economics for each of those individual scenarios. Figure A-1 in Appendix A is the Universal Legend for transmission lines and generation. Figure A-2 in Appendix A is the base MISO Centric perspective for the complete MISO footprint as well as the eastern region of PJM, the RTO serving the area of Chicago, Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia. It is a complex diagram containing many potential transmission facilities as well as generation projects.

Figure 6 shows the MISO Centric Perspective from a Wisconsin perspective. This base MISO Centric perspective suggests that a Y-shaped 345 kV high voltage line may be needed in southwestern Wisconsin. One spur would come from the area near La Crosse to Spring Green; another spur would come from northeastern Iowa to Spring Green; and the last connector would be from Spring Green to West Middleton in Dane County. MISO also indicates another potential 345 kV segment in northwestern Wisconsin, and possibly one from the Madison area to an area north of Milwaukee. The lines on these charts are stylized representations of transmission projects that may be needed for reliability, access to renewable resources (such as wind to the west), adequacy, or economic commerce. The broken lines are conceptual. No utility has indicated to the Commission that it has plans to construct any of the facilities in Figure 6. MISO itself cannot build the transmission lines, as that is beyond its charter.

MISO has also explored transmission planning beyond its footprint. This is an area of ongoing significant controversial study and transmission planning. Usable results from these efforts, notably the JCSP, are not expected to be released until early 2009.

Figure 6 MISO Centric Base 345 kV Transmission Plan for Wisconsin



From the Wisconsin perspective, there are currently several controversies surrounding MISO's transmission planning. Some of these are listed below.

- MISO should plan for its own footprint.
- MISO should not dictate to any state that MISO's transmission plan should be the plan put in place.
- MISO should not perform transmission planning using a top-down approach, but rather use an approach that builds on the plans and perspectives developed by individual stakeholders.
- Regional and sub-regional planning should be further explored to ensure Wisconsin's needs are met at the lowest cost.
- The Y-shaped connector project needs further analysis and study.
- MISO's planning approach does not sufficiently factor in local public and stakeholder input.

In summary, MISO's transmission planning can be a very useful tool to advance the debate on the requisite transmission system needed to accommodate numerous objectives, but MISO's approach must not be viewed as the sole determining method.

ATC Transmission Planning Activities

ATC is the largest transmission provider in Wisconsin. The creation of ATC was contemplated in the late 1990s, as a result of federal and state policies and orders, including passage of 1999 Wisconsin Act 9. ATC, a stand-alone transmission company, was created in 2001. ATC's footprint also includes Michigan's Upper Peninsula. Details regarding potential ATC transmission construction projects can be found in Tables A-2 and A-3, and Figure 5.

ATC has identified the following detailed transmission planning processes that it uses:

Network Adequacy Planning

The planning process that encompasses the largest share of ATC projects is Network Adequacy Planning. This process is an overall assessment of the ATC system and its ability to handle growth in electricity consumption, and deliver power under changing system conditions in the future. ATC simulates future conditions, examines weaknesses and models a variety of potential solutions using its publicly posted planning criteria.

Economic Project Planning

Economic Project Planning refers to studies that look for transmission system congestion that has a significant adverse impact on the delivered cost of energy to consumers. ATC uses historical data and future power flow forecasts in models to help identify potential ways to mitigate or relieve those effects.

Distribution to Transmission (D-T) Interconnection Planning

D-T Interconnection Planning examines ways the transmission system may need to expand or interconnect new electric substations that are proposed to support local growth. When business or housing developments are built in areas that previously were rural, the electric system must be expanded to supply new power needs. When local utilities' expansion plans require new interconnections with the transmission system, utilities must submit a load interconnection request form. ATC's load interconnection business practice outlines how they work with utilities to develop the most cost-effective solution and maintain an interconnection queue to help facilitate communication with utilities about these requests.

Transmission to Transmission (T-T) Interconnection Planning

T-T Interconnection Planning examines the impact on the system of transmission expansions outside of and adjacent to ATC's service area. ATC coordinates their assessments of the need for new facilities with the plans for adjacent transmission systems to identify a wider variety of options on a cooperative basis.

Generator to Transmission (G-T) Interconnection Planning

G-T Interconnections Planning studies the impacts that additions or changes in electrical generation outputs have on the transmission system. These impacts often require modifications or expansions of transmission facilities. Requests for interconnection studies of the transmission system must be sent to MISO. ATC works collaboratively with MISO on these studies and also offers supplemental interconnection guidelines for generators wishing to connect new facilities to the ATC transmission system.

Transmission Service Planning

Transmission Service Planning refers to transmission system studies that are required to resolve future delivery issues. A utility's purchase of power request is made to MISO. MISO and ATC determine if there is adequate "available transmission capacity" to accommodate the power purchase. If not, then the studies recommend solutions to deliver the power as requested.

From a Wisconsin perspective, the ATC approach has been used on several approved projects, and is being tested again on a major proposed project in Dane County, the West Middleton to Rockdale project. The advantage of the ATC method is that it is a detailed bottoms-up form of transmission planning with significant input from Wisconsin stakeholders. Two areas of controversy include whether ATC's transmission plans properly synchronize the requirements of a regional transmission grid in the Midwest, and whether ATC may be proposing projects that focus more on increasing the company's size and rate base. To deal with this concern, ATC transmission projects and costs are carefully scrutinized and evaluated by the Commission during appropriate construction application dockets.

Xcel and Dairyland Power Cooperative Planning Activities

Xcel and DPC also provide transmission service on the western and in the northern-western portions of the state. The Xcel footprint also covers eight states from Minnesota and the Dakotas to Colorado and New Mexico. The DPC footprint also includes Minnesota, Iowa, and Illinois.

Xcel and DPC are members of MAPP. MAPP has approximately 43,000 MW of generation and over 21,000 miles of transmission lines. The summer peak is approximately 34,000 MW. The transmission group has approximately a dozen transmission owners and 40 transmission user members. On behalf of its members, MAPP filed an Attachment K with FERC which describes the comprehensive transmission planning process it will be using. Individual members have also supplied additional information on particular local planning processes. The near term transmission construction plans of Xcel and DPC can be found in Tables A-2 and A-3. A major project that is expected is a transmission facility linking the Minneapolis-St. Paul area to Rochester, Minnesota, and then crossing into Wisconsin near the north La Crosse area. The Commission expects a construction application on the crossing of the Mississippi River near the end of 2008. Partners proposing this line indicate that the 345 kV facility would foster greater transmission system reliability.

Integrated Generation and Transmission Planning

The above discussion highlights the extremely complicated nature of transmission planning and perhaps requires a new interpretation, allowing all entities to engage in or perform transmission planning within certain confines and with certain understandings. This 2008-2014 draft SEA allows for comments on the above planning processes considering the multiple aspects of Wisconsin, MISO, and approaches in other MISO states such as those in MAPP.

As long as EHV projects are not dictated to Wisconsin, one may view the various transmission grid designs not as the *plan* but as an ongoing *strategic analysis*, requiring the ongoing use of an informed *stakeholder process* considering all the multiple dimensions and questions outlined earlier. In other words, transmission planning takes on the form of a dialogue, but that dialogue must be in all directions.

For the Commission, strategic analysis is not focused on a specific generation or transmission planning outcome or optimized map of assorted projects, but on a vetting of many potential generation construction and transmission grid possibilities. Using a financial analogy, the Commission must construct a portfolio of transmission investments in conjunction with neighboring states that is robust enough to last through numerous uncertainties facing the nation, while continuing to match the risk tolerance of the owner(s) and the customers' ability to pay along the way.

Recently, an important new transmission planning exercise commenced that could form the basis of that strategic analysis or dialogue. ATC, as a part of its ten-year plan, is continuing to look at economic transmission planning for its footprint. ATC held an initial stakeholder meeting in February 2008 in which sub-regional transmission planning was discussed with stakeholders, including neighboring transmission owners. Subsequent meetings were held in June 2008. The meetings summarized historical congestion locations, causes, and severity. To find economic solutions, a series of future scenarios are being modeled for analysis. These include:

1. Robust economy
2. High retirements (older coal)
3. Environmental ($25/ton CO_2)
4. Slow growth
5. Potential DOE wind mandate
6. Regulatory limitations

ATC has been collecting preliminary comments and it will post preliminary results and collect further comments on this sub-regional planning in the near future. ATC will also compile a project list and associated assumptions. There is expected to be additional analysis and interaction with stakeholders. By November 2008, a final list of sub-regional projects may be available. The final projects then will move through the regulatory process. The sub-regional approach has the potential to address one of the earlier cited concerns that an ATC-only approach does not properly syncronize with neighboring systems. For instance, this approach will examine the Y-shaped connector project.

Transmission Planning Summary

ATC, Xcel, DPC, MISO, *et al.*, are doing transmission planning under FERC Order No. 890. The key is to make sure that Wisconsin interests are protected. These interests include low costs to ratepayers, as well as preserving state's rights issues. The Commission emphasizes that states should have a significant role in deciding what projects should be built in their states. The joint effort by ATC, Xcel, DPC, *et al.*, is a good start to developing a regionally beneficial plan for Wisconsin. Because the Commission must be involved in planning does not mean that the Commission endorses or approves any specific plan or the projects in that plan. Individual projects must receive scrutiny by the Commission in appropriate construction dockets as prescribed by state law. The Commission is involved in all of the transmission planning efforts mentioned in this report and recognizes the challenges in balancing regional planning and state authority.

The Commission will also be providing significant input to the numerous MISO transmission planning studies, either directly or through the Organization of MISO States.

Market Analysis and Planning Reserve Margin Forecasts

This section provides an assessment of Wisconsin's electric industry as it addresses four concerns mandated by law. Wis. Stat. § 196.491(2)(a) specifically requires the SEA to assess: (1) the extent to which the regional bulk power market is contributing to the adequacy and reliability of the state's electrical supply; (2) the adequacy and reliability of purchased generation capacity and energy to serve the needs of the public; (3) the extent to which effective competition is contributing to a reliable, low-cost, and environmentally sound source of electricity for the public; and (4) whether sufficient electric capacity and energy will be available to the public at a reasonable price.

The following sections address the above concerns. The analysis incorporates data submitted by the electricity providers in their SEA submissions and other data collected by Commission staff.

AN ASSESSMENT OF THE EXTENT TO WHICH THE REGIONAL BULK POWER MARKET IS CONTRIBUTING TO THE ADEQUACY AND RELIABILITY OF THE STATE'S ELECTRIC SUPPLY

New natural gas-fired peaking and intermediate load generation, improvements to the intra-state transmission system, and additional experience with the regional energy market are significant changes that have occurred since the last SEA.

Looking forward, three new large coal-fired baseload facilities are expected to begin commercial operation between 2008 and 2010. One new large intermediate load natural-gas fired facility is expected to begin commercial operation in 2008.

To comply with the Wisconsin renewable energy portfolio, wind generation in Wisconsin and in neighboring states either owned or under contract to Wisconsin utilities is expected to add additional intermittent generation capacity of several hundred MW between now and 2015.

As new generation capacity continues to be brought into service, the amount of capacity purchases through purchased power agreements is expected to drop significantly through 2014. As can be seen in Table 1, capacity purchases made on a system basis are expected to drop from 725 MW in 2006 to 622 MW in 2014. Yet reliability is expected to remain robust with a planning reserve margin forecast through 2012 above 17 percent. Planning reserve margins are often finalized through capacity purchases made a short time ahead of any shortfall. Wisconsin, even seven years into the future, has established planning reserve margins that are very robust this far ahead of need. The current estimate for seven years hence is nearly 12 percent.

The sale of the Point Beach Nuclear Power Plant from WEPCO to FPLE-Point Beach, a subsidiary of the Florida Power and Light holding company, completes the sale of Wisconsin's utility-owned nuclear power plants to organizations specializing in the ownership and operation of fleets of nuclear generation facilities. As part of the sale, WEPCO entered into a life-of-license renewal purchased power agreement, securing the energy production from the facility for the utility and its customers until the two nuclear units' current licenses expire in 2030 and 2033.

Also noted in Table 1, the MWs of capacity under contract from merchant power plants is expected to rise from 3,518 MW in 2007 to 4,088 MW in 2008. This increase is because of the sale of the Point Beach Nuclear Power Plant to FPLE-Point Beach from WEPCO after the summer 2007 peak. Even with the sale of the Kewaunee Nuclear Power Plant and the Point Beach Nuclear Power Plant, and the associated power purchase agreement by the former utility owners for the capacity and energy from the facilities, MW of capacity from merchant power plants drops from 4,083 in 2008 to 2,487 MW in 2013. 2013 is the last year of the power purchase agreements between WPSC and WP&L, the two previous utility owners of the Kewaunee Nuclear Power Plant and Dominion Energy Kewaunee, the current owner of Kewaunee. The drop in capacity under contract is directly linked to the expansion of utility-owned generation during this time frame. After 2013, changes in capacity under contract will depend, at least in part, on whether or not the power purchase agreements for capacity and energy from the Kewaunee Nuclear Power Plant are renewed.

Planning reserve margins were a major concern in the earliest SEAs. In the second half of the 1990s actual reserve margins fell to less than 10 percent four out of five years. The lowest actual reserve margin fell to 6.7 percent in 1995. By contrast, the actual reserve margin in 2006 was 20.4 percent and for 2007 was 19.1 percent. 2006 was a cool summer, but had one very intense heat wave at the end of July continuing into the first two days of August. At that time, MISO hit a peak demand that was not exceeded in 2007. The robust planning reserve margin in Wisconsin in 2006 provided an extra measure of reliability protection for Wisconsin utilities and their ratepayers. Current high reserve margins come at a cost and the Commission's recent lowering of the reserve margin requirements will help to balance cost with reliability.

Sufficient capacity remains only half of the story. Getting the power from the generation source to the load is the second half. Wisconsin's current transmission system has numerous constraints that limit the unfettered flow of electricity into and within the state. These numerous constraints led MISO to name the Wisconsin Upper Michigan System (WUMS) area of Wisconsin and Michigan as a narrowly constrained transmission area. For five years there are special protections available to Wisconsin and Michigan to avoid undue prices on electricity in the wholesale market. It is expected that the current and ongoing transmission system expansion and improvements will greatly enhance the ability to move electricity into and within Wisconsin by 2010 when the special protections will be withdrawn.

AN ASSESSMENT OF THE ADEQUACY AND RELIABILITY OF PURCHASED GENERATION CAPACITY AND ENERGY TO SERVE THE NEEDS OF THE PUBLIC

Purchased generation capacity and energy may occur from facilities located within Wisconsin or from facilities located outside of Wisconsin. For the moment, NSPW and SWP&L will be considered separately. These two utilities have Minnesota-based affiliates where much of their generation capacity and energy needs are met as though they were part of the affiliates' system. The Wisconsin utilities in the eastern portion of the state are not part of multi-state affiliate networks that dispatch electricity across multiple states as a system. These WUMS utilities were well-placed in the late 1980s and throughout the early to mid-1990s to make purchases of excess generation capacity and energy, especially from Illinois. This became more problematic as the transmission grid was opened up via open access under policy direction of FERC in 1996. Thus, much of the past discussion in the initial SEAs on purchased generation capacity and energy focused on imports of generation capacity and energy, specifically their availability in light of increasing transmission congestion.

Several things have changed in recent years with respect to purchased generation capacity and energy. The aforementioned sales of the Kewaunee Nuclear Power Plant and the Point Beach Nuclear Power Plant have significantly broadened the purchased power market to include baseload generation in addition to the combustion turbine and combined-cycle generation that has a much lower capacity factor. The combustion turbine market is usually a market that focuses on generation capacity that is only expected to be used around 5 to 10 percent of the time. Combined-cycle units have higher capacity costs but are much more efficient. For the higher capacity costs, but lower generation costs, these plants are expected to be used from between 25 percent of the time to perhaps even more than 70 percent of the time, depending upon fuel costs. A nuclear powered baseload plant has very high capacity costs, but very low cost of generation. For a nuclear power plant (and to a lesser extent a large coal-fired baseload plant) to be commercially viable, it needs to be used with capacity factors of at least 80 percent.

When comparing the market for purchased generation capacity in 2008 to the same market in 2000, more of the purchased generation capacity and energy will be from facilities in Wisconsin. While some independent power producer (IPP) combustion turbines have been purchased by Wisconsin utilities, the sale of the state's three nuclear units to groups specializing in the operation of nuclear power plants has resulted in far larger amounts of capacity and energy now being sourced by IPPs in Wisconsin. With the purchase of nuclear baseload energy, more GWh of total energy will be purchased than in the past.

The market for purchased generation capacity and energy continues to evolve. The Commission continues to watch developments at MISO and how generation capacity and energy markets continue to change. At the same time, the Commission found in the Kewaunee and Point Beach cases that concerns, including reliability concerns, can be overcome to allow the sale of a rate base baseload plant with a power purchase agreement that protects Wisconsin ratepayer interests.

AN ASSESSMENT OF THE EXTENT TO WHICH EFFECTIVE COMPETITION IS CONTRIBUTING TO A RELIABLE, LOW COST, AND ENVIRONMENTALLY SOUND SOURCE OF ELECTRICITY FOR THE PUBLIC

The issue of reliability has been addressed in the previous sections of this report. This section will deal with the low cost and environmentally sound provisions required by statute.

FERC has the authority under federal law to regulate the market for wholesale power. As part of FERC's regulatory responsibility, it established rules for regional transmission authorities and to allow those regional transmission authorities to establish markets for energy. This has culminated in the Day 2 market under MISO that sets day ahead and real time prices for energy on a location by location basis throughout the area served by utilities participating in MISO. All Wisconsin utilities are part of MISO.

Figures 7 and 8 show the on-peak LMP from April 1, 2005, through December 31, 2007, for four MISO price points—an Illinois hub price compared to a Wisconsin load node price, WEC.S, the price node for the southern Wisconsin load of WEPCO, and the Minnesota hub price compared to the price node for the Wisconsin load served by WPSC, WPS.WPSM. The WEC.S node is representative of LMPs set for southern Wisconsin. The WPS.WPSM node is representative of LMPs set for northern Wisconsin. The Minnesota hub price looks at prices to the west of Wisconsin and the Illinois hub price looks at prices to the south of Wisconsin. The west and the south are the two primary paths of imported power into Wisconsin.

At the inception of the MISO Day 2 market on April 1, 2005, both of the Wisconsin node prices were often out of step with prices to the west and to the south. This is an indication of transmission constraints that cause either congestion charges or loss charges to push the LMP prices apart. In MISO, the energy charge in the LMP is always the same for all areas. All LMP price differences can be attributed to differences in congestion and/or loss charges.

As new transmission links to the south (primarily the 345 kV connection between Wempletown and Paddock) and new generation within the state (primarily new natural gas-fired combined-cycle units) came on line, the WEC.S and Illinois hub LMPs converged. LMPs in northern Wisconsin, as represented by the WPS.WPSM node, continue to track more closely to the Minnesota hub. Because of persistent transmission concerns in Minnesota and Iowa, a portion of this area has now also been identified by MISO as a narrowly constrained area. It is anticipated that the spring 2008 energizing of the remaining portion of the Arrowhead-Weston 345 kV line and the commercial operation of the new Weston 4 power plant will begin to relieve the congestion and loss issues that are likely to be a root cause of the LMP deviation between southern and northern Wisconsin LMP nodes. In late 2009, when the Gardner Park-Central Wisconsin, Morgan-Werner West, and Werner West-Clintonville transmission projects are completed, there is likely to be additional relief on the congestion and loss charges driving differentials in the LMPs between southern and northern Wisconsin. Far western Wisconsin, which is closely identified with the narrowly constrained issues facing southeastern Minnesota and northeastern Iowa, is likely to need other transmission system improvements to more closely align Minnesota hub prices with LMP prices in the rest of MISO.

Figure 7 Average Hourly Day-Ahead LMP for WEC.S and Ill.Hub

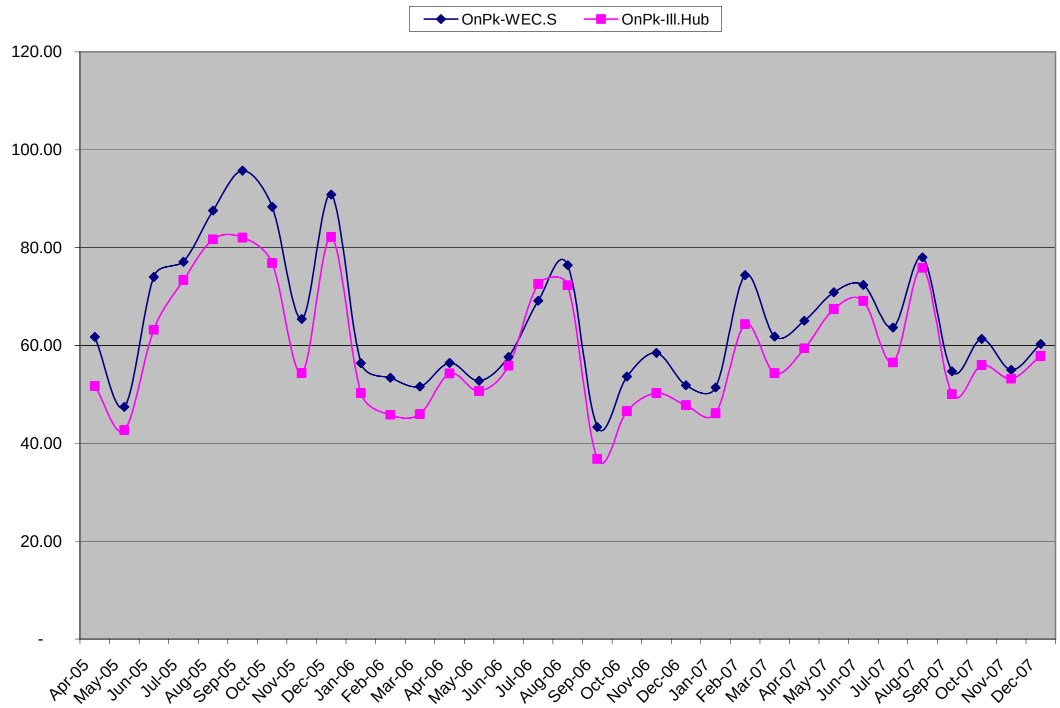
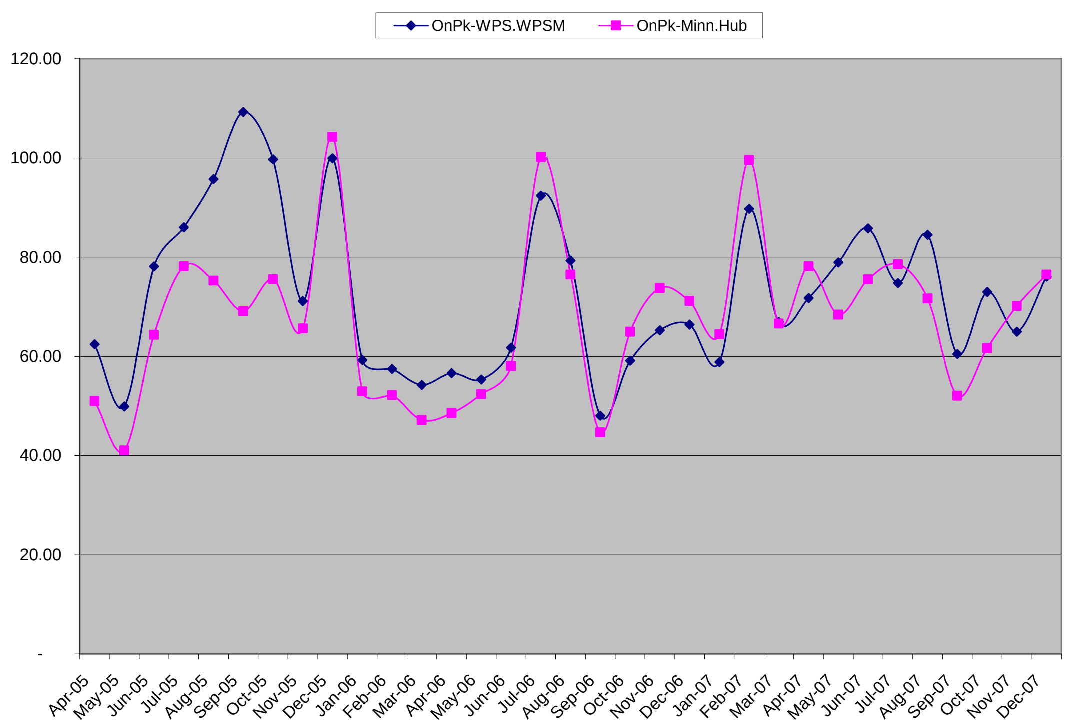


Figure 8 Average Hourly Day-Ahead LMP for WPS.WPSM and Minn.Hub



The final topic in this section is an assessment of the third statutory requirement—whether competitive markets are contributing to an environmentally sound source of electricity for the public. According to conventional economic theory, competitive markets will consider all direct economic costs as well as any indirect costs associated with externalities, such as pollutants, as long as the externalities in question have been regulated by either command and control methods or by some form of monetization in the form of taxes or emissions allowance trading, for instance. In cases where legitimate externalities have not been so factored in, the competitive marketplace will ordinarily ignore any of the non-private costs associated with such externalities. There may be some exceptions in cases where the public may be willing to pay a premium for goods or services with a better environmental footprint. In Wisconsin, such an example might be individual utilities offering up their green pricing programs whereby customers may buy wind power.

FERC has regulatory authority over MISO. MISO dispatches generation and transmission assets to facilitate wholesale competition in the interstate electric power market. The Commission remains vigilant in monitoring the MISO tariff with FERC and in participating directly with MISO and with our sister states to assure that the MISO is obtaining the promised benefits of lowering the cost of wholesale electricity. The Commission remains concerned that while the MISO is obtaining benefits in lowering electric production prices it is not clear that the regulatory and administrative costs associated with securing lower prices are significantly greater than the benefits of lower wholesale electric prices.

With this background, competitive power markets have been contributing to an environmentally sound source in the cases of pollutants and externalities that are under public policy supervision. Examples would include SO_2, NO_x, particulate pollution, and mercury. On the other hand, competitive power markets may not be contributing to an environmentally sound source in the cases of pollutants and legitimate externalities that are not under appropriate or adequate public policy supervision. Examples might include mercury deposition, permanent nuclear waste disposal, and greenhouse gases.

The Commission has directed Commission staff to work with the GWTF to assist the GWTF and its working groups in gathering and analyzing the data needed to develop sound policy recommendations as Wisconsin, the nation, and the world begin to address the most significant environmental issue of our time. The Commission also continues to assist the Department of Natural Resources (DNR) with technical support as DNR works to implement the governor's goal of reducing mercury emissions from coal-fired power plants by 90 percent.

The Commission will continue to work on the myriad issues associated with balancing environmental protection with reliable and affordable electric energy.

AN ASSESSMENT OF WHETHER SUFFICIENT ELECTRIC CAPACITY AND ENERGY WILL BE AVAILABLE TO THE PUBLIC AT A REASONABLE PRICE

The previous SEA spent some time discussing this topic. As noted previously, the Commission has approved CPCNs for three new large coal-fired baseload generation units. The Commission has also approved CPCNs for new combined-cycle natural gas generation, wind generation, and combustion turbine natural gas generation. As noted in Table 1, planning reserve margins are projected to be above, or very close to, 18 percent through 2012. Both the magnitude and the mix of new electric generation appear to answer the statutory concern about sufficient capacity in the affirmative. Wisconsin's electric generation future is in much better shape now than it has been in the past with respect to capacity and energy.

Several questions regarding the capacity and energy infrastructure remain:

First, Wisconsin still has as part of its generation fleet several very old, small coal-fired boilers. These units tend to have low levels of efficiency and tend to be much harder to control to meet pollution reduction requirements. The federal courts have vacated both the U.S. Environmental Protection Agency's (EPA) Clean Air Mercury Rule (CAMR) and Clean Air Interstate Rule (CAIR). DNR has adopted a state-specific mercury rule that creates a multiple year plan to achieve the governor's goal of a 90 percent reduction in mercury emissions. The rule has been adopted by the Natural Resources Board and is now awaiting review by the legislature. The adopted rule not only has a workable time line for installing equipment at the largest mercury emitting electric generating facilities in Wisconsin, it also recognizes the inherent difficulties in achieving mercury controls at the smaller electric generating facilities and provides for specific mercury control reviews for these units that will include a review of the economic consequences of achieving mercury reductions at these smaller facilities.

The vacature of the EPA's CAIR package is unlikely to absolve any electric generation facilities in Wisconsin from future emission reduction obligations. The multi-pollutant option in the Wisconsin mercury rule may provide a path for utilities to install pollution control equipment that is likely to be needed in a manner that maintains affordable and reliable electric energy for Wisconsin. The PSC will continue to take note of the likely next steps in NO_x, SO_2, and mercury emission controls, and will be ready to provide technical assistance to DNR and report to the legislature on these issues as requested.

Second, the state has implemented a renewable energy portfolio requirement. Currently wind generation is the lowest cost renewable energy option. Renewable energy portfolio requirements will affect Wisconsin's optimal energy expansion path. CPCNs for multiple wind farms have been approved by the Commission and are under construction. Additional applications for wind farms have been received by the Commission or are expected very soon. Several of the new applications are for wind farm development outside of Wisconsin. Areas in Iowa and Minnesota have much more favorable wind profiles than can be found in Wisconsin and these sites have been increasingly attractive to wind farm developers. Wisconsin, in 2008, has a significant fleet of combustion turbines and combined-cycle units.

These units are critical to a generation fleet with significant wind capacity. Wind, while having very low marginal costs of generation, has unpredictable availability. To complement the low and unpredictable availability factor for wind, there needs to be rapidly available alternative generation capacity. Natural gas-fired combustion turbines and combined-cycle units can fill this need. This may imply higher capacity utilization for combustion turbines and combined-cycle units. This raises a concern as Wisconsin does have a number of older combustion turbines, some running on fuel oil. It has been economic to hold onto these units given their relatively low capacity utilization. However, if wind resources are expanded either in Wisconsin or outside of Wisconsin for use in Wisconsin, some combustion turbines may need to be replaced with newer, more reliable and less polluting units. With any generation planning scenario, Wisconsin's geography must be taken into consideration, *i.e.* geographic limitations like the Great Lakes.

It is possible that the renewable portfolio requirements will delay the need for both new baseload facilities and new peaking facilities. Although there are limitations created with variable generation in planning efforts, it is possible to mitigate some of the variation. It is paramount that integrating wind into generation portfolios be accomplished.

The capital costs of all forms of electric generation capacity have increased substantially since the last SEA. Over the past two years construction costs have increased, driven by tight markets for skilled labor, rapidly rising prices of critical construction materials including copper, steel, and cement, escalation in energy prices that feed into the higher cost of construction materials, and increased demand for critical generation components such as turbines and transformers fueled by rapidly growing economies such as China and India. The capital cost of new capacity has, perhaps, more than doubled in the past two years. This will inevitably lead to rate increases.

At the same time, the rate of growth in the amount of energy consumed and the growth in peak demand have tempered the need for new capacity, especially peaking capacity. The Commission will continue to carefully weigh the need for new capacity, as well as the optimal generation mix, as we move forward.

Rates

It should be noted that direct rate comparisons are becoming less meaningful as states are at different points in the construction of new power plants and some states have deferred rate increases to commence in years after 2009. For instance, in the Midwest there are many regulatory rate structures in place. Among the existing regulatory rate structures, there are states with vertically integrated utilities and states with stand-alone transmission companies, like Wisconsin. Fuel cost treatment varies from state to state, as well as treatment for deferrals of many different costs. In some states, rate reductions and freezes enacted by the legislature are soon to expire; some have already expired. The good news is that Wisconsin is ahead of other states with respect to the construction cycle of new electric generation and transmission facilities needed to address future service reliability.

According to the Energy Information Administration's (EIA) reported rate information in its Electric Power Monthly–March 2008 report, Wisconsin's 2007 electricity rates for residential customers—10.72 cents/kWh—were higher than the Midwest average of 9.40/kWh and very close to the national average of 10.65/kWh. Commercial rates in Wisconsin for 2007—8.64/kWh—are lower than the national average of 9.68/kWh. Industrial rates—6.18/kWh—were higher than the Midwest average of 5.65/kWh, but lower than the national average of 6.38/kWh. Fuel prices and purchased power cost increases, as well as construction costs for generation and transmission facilities, are the significant drivers of recent rate increases. Rate increases can be mitigated somewhat with energy conservation, innovative utility financing related to environmental trust fund programs, and other new rate options.

Changes in the ownership of electric generation and transmission facilities, construction and timing of new utility generation plants, changing fuel costs, and the emergence of the MISO Day 2 Market for power have had, or will have, a profound impact on the rates Wisconsin customers pay, as well as how Wisconsin rates compare to other states' electricity rates.

Tables 8, 9, and 10 summarize average rates for residential, commercial, and industrial rates in the Midwest and the country.

Table 8 Residential Average Rates in the Midwest and U.S. (in cents)

	2000	2001	2002	2003	2004	2005	2006	2007
Illinois	8.83	8.70	8.40	8.38	8.37	8.34	8.56	10.33
Indiana	6.87	6.90	6.90	7.04	7.30	7.49	8.25	8.06
Iowa	8.37	8.40	8.30	8.57	8.96	9.36	9.77	9.41
Michigan	8.53	8.40	8.50	8.35	8.33	8.60	9.81	10.34
Minnesota	7.52	7.60	7.50	7.65	7.92	8.34	8.74	9.02
Missouri	7.04	7.00	7.10	6.96	6.97	7.08	7.62	7.72
Ohio	8.61	8.30	8.10	8.27	8.45	8.50	9.45	9.59
Wisconsin	7.53	7.90	8.10	8.67	9.07	9.64	10.5	10.72
Midwest Average	**7.97**	**7.90**	**7.83**	**7.89**	**8.17**	**8.42**	**9.09**	**9.4**
U.S. Average	**8.21**	**8.57**	**8.43**	**8.70**	**8.97**	**9.42**	**10.47**	**10.65**

Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Reports

Table 9 Commercial Average Rates in the Midwest and U.S. (in cents)

	2000	2001	2002	2003	2004	2005	2006	2007
Illinois	7.53	7.40	8.30	7.22	7.54	8.05	8.04	9.01
Indiana	5.93	5.80	6.00	6.13	6.31	6.54	7.23	7.16
Iowa	6.57	6.70	6.60	6.24	6.75	6.95	7.45	7.19
Michigan	7.90	7.60	7.50	7.55	7.57	8.09	8.51	8.98
Minnesota	6.36	6.00	5.90	6.12	6.31	6.56	7.1	7.47
Missouri	5.83	5.90	5.90	5.78	5.80	5.88	6.27	6.45
Ohio	7.61	7.90	7.70	7.60	7.75	7.92	8.44	8.64
Wisconsin	6.03	6.40	6.50	6.97	7.24	7.61	8.4	8.64
Midwest Average	**6.82**	**6.76**	**6.84**	**6.66**	**6.91**	**7.20**	**7.68**	**7.94**
U.S. Average	**7.36**	**7.91**	**7.93**	**7.98**	**8.16**	**8.68**	**9.51**	**9.68**

Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Reports

Table 10 Industrial Average Rates in the Midwest and U.S. (in cents)

	2000	2001	2002	2003	2004	2005	2006	2007
Illinois	4.76	4.80	5.60	4.91	4.65	4.52	0.69	6.02
Indiana	3.81	4.00	4.00	3.92	4.13	4.40	4.99	4.98
Iowa	3.89	4.20	4.00	4.16	4.33	4.57	5.01	4.86
Michigan	5.10	5.20	4.90	4.96	4.92	5.58	6.05	6.52
Minnesota	4.57	4.60	4.20	4.36	4.63	5.06	5.27	5.78
Missouri	4.43	4.50	4.50	4.49	4.62	4.59	4.74	4.88
Ohio	4.47	4.70	4.70	4.79	4.89	5.03	5.6	5.78
Wisconsin	4.04	4.30	4.40	4.71	4.93	5.33	5.86	6.18
Midwest Average	**4.43**	**4.57**	**4.56**	**4.51**	**4.64**	**4.89**	**5.28**	**5.63**
U.S. Average	**4.57**	**5.07**	**4.84**	**5.13**	**5.27**	**5.57**	**6.19**	**6.38**

Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Reports

Energy Efficiency and Renewable Resources

ENERGY EFFICIENCY

Status of Energy Efficiency Efforts

Conservation and energy efficiency efforts encourage customers to reduce their use of electricity. Conservation saves energy or reduces demand by reducing the level of energy services (*e.g.* turning off lights, changing thermostat settings, taking shorter showers, etc.). Conservation generally involves behavioral changes. Energy efficiency is the application of technologies that use less energy while producing the same or a better level of energy services. These technologies are generally long-lasting and save energy whenever the equipment is in operation. Through the reduction in energy use, conservation and energy efficiency provide an important means for customers to control their electric bills. Conservation and energy efficiency have the additional benefit of reducing the need to build new power plants or transmission lines.

Prior to 2000, utilities had primary responsibility for energy efficiency services. 1999 Wisconsin Act 9 (Act 9) established a new mechanism, administered by the Department of Administration (DOA), for the funding and delivery of energy efficiency programs. Under Act 9, DOA contracted with third-party program administrators for the development and delivery of statewide energy efficiency (Focus on Energy (FOE)) programs. Energy efficiency programs through DOA-administered FOE programs were first made available to ratepayers in 2001 and remained in place until July 1, 2007.

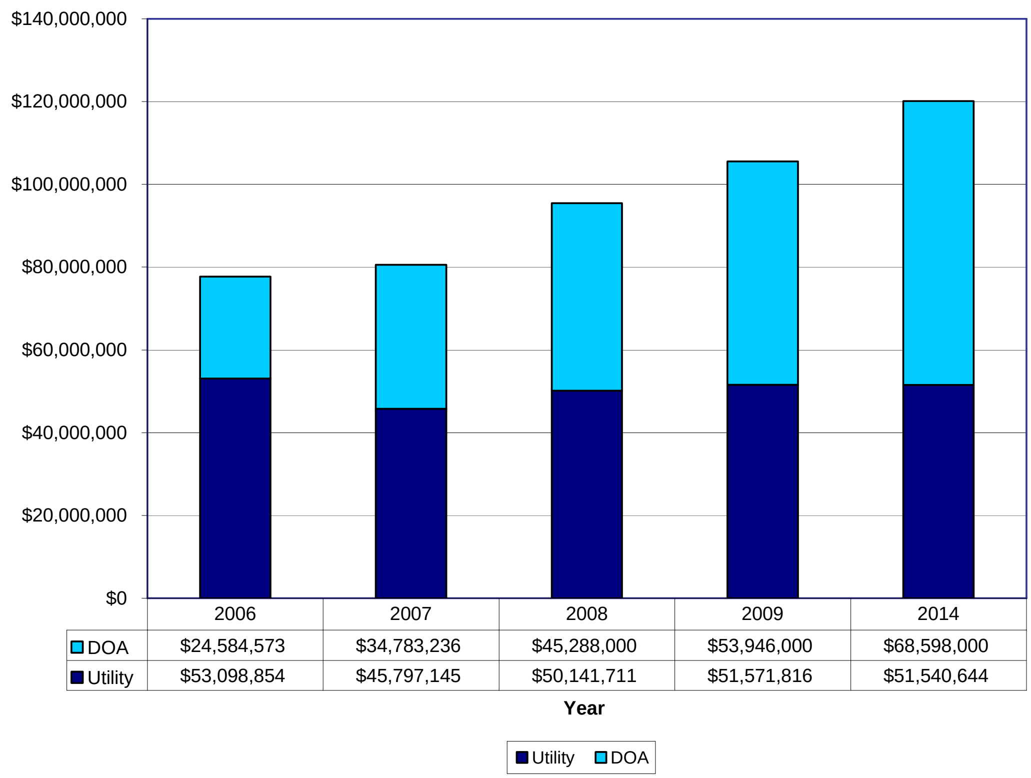
2005 Wisconsin Act 141 (Act 141) substantially revised the funding and structure of the statewide energy efficiency programs. Beginning July 1, 2007, the FOE programs are collectively funded by investor-owned utilities. In order to secure funding for the programs, the utilities directly contract with the program administrators. Funding of the FOE programs was increased to 1.2 percent of annual operating revenues. However, in years 2007, 2008, and 2009, a portion of this funding is retained by the utilities for their ordered programs.[4] Act 141 also provides the Commission oversight of the FOE programs.

The following figures provide the aggregate historical and projected electric conservation and energy efficiency expenditures, kW, and kWh savings of Wisconsin utilities, and the FOE programs for calendar years 2006-2009 and 2014. The charts include the aggregate

[4] WEPCO and WPSC have energy efficiency programs that were required as conditions of orders in power plant approvals.

expenditures and savings of the following utilities: MGE, NSPW, Superior Water, Light and Power, WEPCO, WP&L, and WPSC. Expenditures and savings for DPC and WPPI are also included.[5] Utility customer service conservation expenditures are included. However, little or no savings are reflected for utility customer service conservation activities. This is because many of these services do not lend themselves to tracking and verifying the savings. FOE savings projections are based on the assumption of continued utility funding at a level of 1.2 percent of operating revenues.

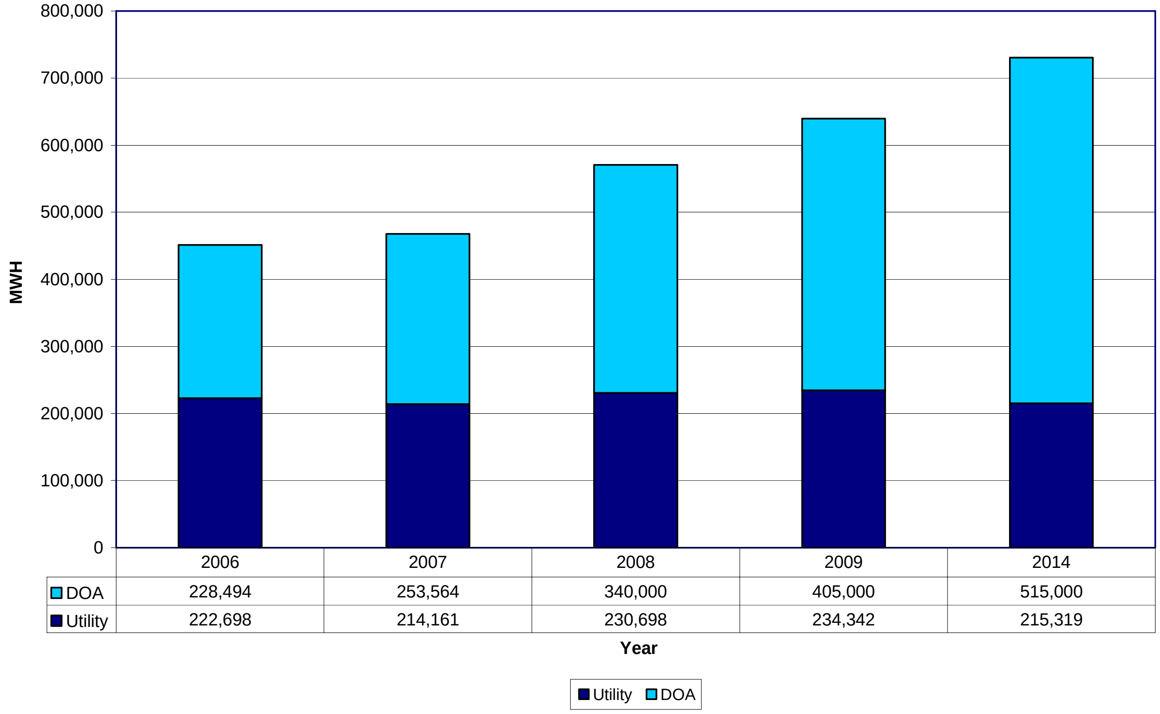
Figure 9 Annual Energy Efficiency Expenditures (2006-2012)



	2006	2007	2008	2009	2014
DOA	$24,584,573	$34,783,236	$45,288,000	$53,946,000	$68,598,000
Utility	$53,098,854	$45,797,145	$50,141,711	$51,571,816	$51,540,644

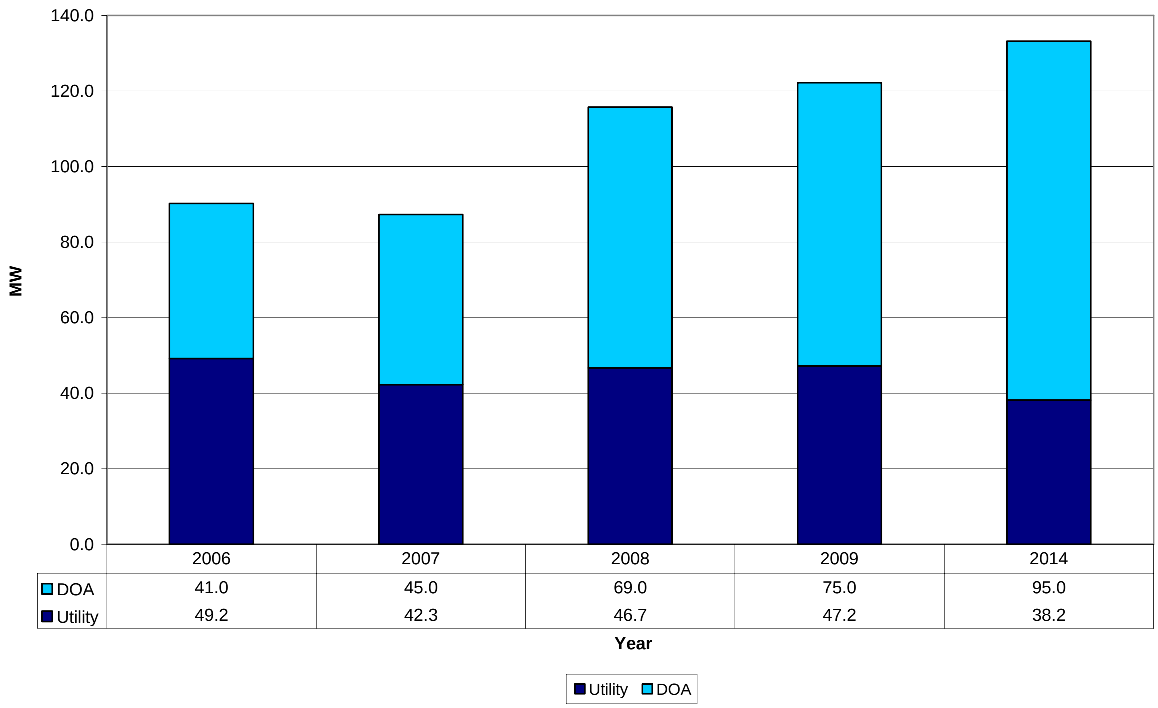
[5] Although electric cooperatives and municipal utilities that are not members of DPC or WPPI also provide conservation and energy efficiency services, their costs and savings are not included. Not all of these electric cooperatives and municipal utilities track achievement of energy and demand savings. Total spending of these utilities are less than 1 percent of the total expenditures of the utilities included in the figures. Because of the relative size of the electric cooperatives and municipal utilities, this omission does not greatly affect the aggregate totals.

Figure 10 Annual Energy Savings



	2006	2007	2008	2009	2014
DOA	228,494	253,564	340,000	405,000	515,000
Utility	222,698	214,161	230,698	234,342	215,319

Figure 11 Demand Savings



	2006	2007	2008	2009	2014
DOA	41.0	45.0	69.0	75.0	95.0
Utility	49.2	42.3	46.7	47.2	38.2

Analysis of Energy Efficiency Efforts

In the past there has been inadequate energy efficiency funding, resulting in a less than desirable level of energy efficiency savings. Funding for the FOE programs was determined by the legislature after considerable debate among various stakeholders. It was not based on an analysis of energy efficiency potential and the cost to achieve that potential. The GWTF recommends increasing the capture of energy efficiency savings from the current annual reduction of 0.4 to 0.5 percent of electric usage to 2 percent by 2015. The GWTF suggests that a substantially higher funding level than the current 1.2 percent of operating revenues will be needed to capture maximum achievable potential.

The Commission is in the process of securing a contractor to conduct an energy efficiency potential study. The energy efficiency potential study will not only estimate maximum achievable potential, but also provide information regarding program designs and level of resources required to capture the identified potential. The results of this study will inform the Commission's first Act 141-required energy efficiency planning process, expected to occur in 2009. In this planning process the Commission will establish priorities, set overall energy efficiency savings targets, and set funding levels to reach these targets. The level of savings recommended by the GWTF is aggressive. This level of savings has not been achieved, on a statewide basis, by any current portfolio of programs. If the energy efficiency potential study indicates that it is possible to achieve the GWTF's recommended annual reduction of 2 percent of electric use, and sufficient funding is available, it will still be a challenge to identify the set of programs and policies that will be able to capture the savings. If funding above the current 1.2 percent of operating revenues is needed to meet the energy efficiency savings targets, the Commission can, with Joint Committee on Finance approval, require the utilities to spend a larger share of their operating revenues on statewide energy efficiency programs. If sufficient funding is not available to meet the Commission's established targets, the Commission will need to make some difficult choices regarding the priorities of the energy efficiency programs. For instance, the Commission may have to determine whether the programs should emphasize demand savings, which addresses reliability, or energy savings, which addresses greenhouse gas emissions.

RENEWABLE RESOURCES

Generation of Electricity from Renewable Resources

The generation of electricity from renewable sources is expected to increase steadily during the planning period. This growth will come from three areas—onsite customer generation, green pricing programs, and utility efforts to comply with the RPS. In 2006, about 2,644,228 MWh or 3.86 percent of all electrical energy sold in Wisconsin was generated from renewable resources.

Currently, Wis. Stat. § 196.378(2) requires all retail electric providers to provide a minimum portion of their total retail sales from renewable resources. A renewable resource baseline was established for each electric provider. By 2010, each electric provider is required to increase its renewable energy percentage so that it is at least 2 percent above its baseline renewable percentage. The overall effect of this RPS is to require10 percent of Wisconsin's total electric energy consumption in 2015 (and thereafter) to come from renewable resources. In 2006, all electric providers and aggregators were in compliance with the RPS.

The GWTF recommends the current RPS be amended to move the 10 percent renewable requirement forward from 2015 to 2013. The GWTF also recommends standards of 20 percent renewable energy by 2020 and 25 percent by 2025. An amended RPS would also include a minimum amount of the renewable energy come from Wisconsin-based renewable energy resources. This minimum amount would be 6 percent by 2020 and 10 percent by 2025.

In 2007, the Midwest Renewable Tracking System (M-RETS) was established and began issuing renewable energy certificates (REC). M-RETS is an electronic tracking and accounting system designed to support the growing market for RECs and green power in the Midwest. M-RETS is used to demonstrate compliance with Wisconsin's and other regional RPS. M-RETS also facilitates regional trading of RECs.

Customer Sited Renewable Generation

A portion, approximately 4.5 percent, of public benefit energy dollars go to the FOE renewable energy program operated by Wisconsin Renewable Energy Network. For the calendar year 2007, the FOE renewable energy program had a budget of about $3,300,000. The budget for calendar year 2008 increased to $5,500.000. Technologies covered by the FOE program include:

- Photovoltaic or solar electric;
- Small-scale wind;
- Biomass;
- Heat pumps;
- Solar water and space heating.

Incentives to encourage greater use of these renewable technologies by utility customers include cash backs awards, implementation grants, business and marketing grants, demonstration grants, feasibility grants, and technical assistance.

In calendar year 2007, energy savings produced by the FOE renewable energy program were about 6 million kWh and 600,000 therms.

Environmental Issues

Wisconsin's SEA for 2008-2014 describes energy issues influenced by three forces: global warming; federalization of the electric system; and increasing energy costs. The timing and rate at which each of these forces will develop and affect Wisconsin's energy future are uncertain. Another major influence is the evolving implementation of the National Ambient Air Quality Standards. Many decisions made during this period will determine how well Wisconsin adapts to the forces of change. There is a potential for substantive change and the resultant environmental effects are uncertain.

The importance of energy efficiency, conservation, and load control to reducing Wisconsin's energy costs and environmental impacts is highlighted by the findings of the GWTF, as well as by analysis in the SEA. These energy management strategies also keep more money in the state and produce more Wisconsin jobs.

Rising costs will create hardships for people with low incomes. Provisions must be made to address this problem for public health, safety, and environmental reasons. The GWTF recommendations begin to address this issue.

Global Warming Task Force Recommendations

On July 24, 2008, the GWTF overwhelmingly voted to finalize its report to the governor. Noting the significant impact from the consumption and generation of electricity in Wisconsin's total greenhouse gas emissions profile, the GWTF assembled recommendations both to promote conservation and energy efficiency, and to reduce the greenhouse gas emission profile of electric generation.

ENERGY SECTOR POLICIES

The utility sector was responsible for 34 percent of Wisconsin's greenhouse gas emissions in 2003. Direct fossil fuel use by the commercial and residential sectors was responsible for an additional 14 percent of Wisconsin's greenhouse gas emissions in 2003.

The GWTF recommends policies to aggressively promote much greater energy conservation and efficiency. It concluded that these policies provide the most effective and least costly early action strategies available for reducing greenhouse gas emissions. The policies are grouped into general categories, and call for:

- Enhancing Wisconsin's existing Focus on Energy program through adoption of challenging goals to reduce natural gas and electricity consumption, with substantially increased funding;
- Promoting conservation and efficiency through innovative utility rate designs and demand response programs, and removal of economic disincentives for utilities to aggressively promote and invest in conservation and efficiency measures;
- Adopting and maintaining state-of-the-art residential and commercial building codes and studying whether mandatory efficiency upgrades should be required for existing buildings at time of sale;
- State government taking a leadership role by reducing its own greenhouse gas emissions substantially;
- Creating energy efficiency standards for certain appliances and for lighting in rental properties;
- Promoting and incentivizing energy efficiency projects for schools and low income residences;

- Creating a new program similar to Focus on Energy to promote conservation and efficiency to customers who use propane, coal, or oil for heating; and,
- Promoting water conservation programs to reduce electricity use by water utilities.

The GWTF also recommends policies designed to promote cleaner electric generation technologies. These policies call for:

- Requiring utilities to develop greenhouse gas inventories and voluntary greenhouse gas reduction goals;
- Increasing substantially the amount of electricity produced from renewable resources, reaching 25 percent by 2025;
- Modifying Wisconsin's current moratorium on the construction of new nuclear power plants to allow this option to be considered in the future to meet Wisconsin's energy needs, after the GWTF's recommended policies for conservation, efficiency, and renewable energy are in place; and if certain other conditions are met, including a determination by the Commission that it is safe, economic, and in the public interest;
- Establishing statewide standards for siting wind power projects;
- Improving transmission infrastructure and interconnection processes to facilitate increased renewable energy projects and distributed generation;
- Studying the potential for geologic carbon sequestration and Great Lakes offshore wind power projects; and,
- Exploring new ways to mitigate the cost impacts of greenhouse gas policies on utility rates.

A technical analysis performed for the GWTF projects that these sector-based policies, collectively, may achieve the reductions necessary to meet the 2014 goal, but will only achieve approximately half of the reductions needed to meet the 2022 goal. The GWTF therefore recommends a Cap and Trade Program to help achieve the other emission reductions needed to meet the 2022 reduction goal.

Acronyms

§	Section
Act 9	1999 Wisconsin Act 9
Act 141	2005 Wisconsin Act 141
AFUDC	Allowance Funds Used During Construction
ATC	American Transmission Company LLC
Btu	British thermal units
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CC	Combined-cycle
Commission	Public Service Commission of Wisconsin
CO	Carbon monoxide
CO_2	Carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
CT	Combustion turbine
D-T	Distribution to Transmission
DNR	Department of Natural Resources
DOA	Department of Administration
DOE	U.S. Department of Energy
DOT	Department of Transportation
DPC	Dairyland Power Cooperative
DSM	Demand-side management
ECW	Energy Center of Wisconsin
EGEAS	Electric Generation and Expansion Analysis System
EHV	Extra high voltage
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERF	Electronic Regulatory Filing
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FOE	Focus on Energy
FTR	Financial transmission rights
G-T	Generator to Transmission
GW	Gigawatt
GWh	Gigawatt hour
GWTF	Governor's Task Force on Global Warming
HVAC	Heating/ventilating/air conditioning
IGC	Industrial Customer Groups
IGCC	Integrated gasification combined-cycle
IPP	Independent power producers
JCSP	Joint Coordinated System Plan
JPI	Joint Public Intervenors
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LMP	Locational marginal pricing
MACT	Maximum achievable control technology
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MGE	Madison Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.

mmBtu	Million British thermal units
MPU	Manitowoc Public Utility
M-RETS	Midwest Renewable Tracking System
MTEP	MISO Transmission Expansion Plan
MTEP08	MISO Transmission Expansion Plan 2008
MTEP09	MISO Transmission Expansion Plan 2009
MRO	Midwest Reliability Organization
MW	Megawatt
MWh	Megawatt hour
NAERO	North American Electric Reliability Organization
NERC	North American Electric Reliability Council
NO_2	Nitric oxide
NO_X	Nitrogen oxides
NPV	Net present value
NRC	Nuclear Regulatory Commission
NSPW	Northern States Power-Wisconsin
O&M	Operations and maintenance
Ohio PUC	Ohio Public Utilities Commission
OMS	Organization of MISO States
PHEV	Plug-in hybrid electric vehicle
PJM	PJM Interconnection
PM	Particulate matter
PM_{10}	Particulate matter less than 10 microns in diameter
PM_{25}	Particulate matter less than 25 microns in diameter
PSC	Public Service Commission of Wisconsin
PTC	Production tax credit
PV	Photovoltaic
REC	Renewable energy certificate
ROW	Right-of-way
RTC	Regional Transmission Committee
RTO	Regional Transmission Organization
RPS	Renewable portfolio standard
SCPC	Super-critical pulverized coal
SCR	Selective catalytic reduction
SEA	Strategic Energy Assessment Report
SERC	Southeast Reliability Council
SO_2	Sulfur dioxide
SO_X	Sulfur oxides
SWL&P	Superior Water, Light and Power Company
T-T	Transmission to Transmission
TPSC	Transmission Planning Subcommittee
U.S.	United States
WEPCO	Wisconsin Electric Power Company
WIEG	Wisconsin Industrial Energy Group
Wis. Admin. Code	Wisconsin Administrative Code
Wis. Stat.	Wisconsin Statutes
WMC	Wisconsin Manufacturers and Commerce
WP&L	Wisconsin Power and Light Company
WPC	Wisconsin Paper Council
WPPI	Wisconsin Public Power, Inc.
WPSC	Wisconsin Public Service Corporation
WUMS	Wisconsin Upper Michigan System
Xcel	Xcel Energy, Inc.

GLOSSARY

Capacity	The maximum amount of power that a generating unit can create, usually measured in MW.
Capacity Factor	A calculation, expressed as a percentage such as 70 percent, representing the proportion of time in a year that a generating unit operates at its full electric generating output level.
Demand and Energy Charge	The combined fixed costs for the right to obtain capacity as well as the energy charges that are incurred to produce electricity.
Electric Demand	The amount of instantaneous draw of power from the electric system, usually measured in MW.
Electric Energy	The amount of electricity used over a period of time, measured in MWh.
Energy Charge	The variable costs, including fuel, that are incurred to produce electricity.
Flow Gate	A particular section of the transmission system where energy is monitored for excessive flow.
Focus on Energy Program	Energy efficiency and conservation program administered by the state Department of Administration and funded by the state's electric and gas utilities.
Independent Power Producer (IPP)	A non-utility business that constructs and operates power plants, who sells the electrical output into the marketplace.
Marginal Energy Cost (MEC)	The cost of electric energy for the last unit produced, usually measured in $ per MWh. The MEC is usually comprised of fuel cost, and variable operation and maintenance costs.
Native Load	The amount of electric demand, representing the customers in its service territory that a utility is obligated to serve.
Peak Electric Demand	The amount of instantaneous draw of power from the electric system at the moment of highest use, usually on a hot humid summer day.
Power Purchase Agreement (PPA)	A contract in which an electric generating company sells capacity and energy to a utility.
Therm	A unit used to measure the quantity of heat that equals 100,000 Btu.
Transfer Capability	The amount of electrical output measured in MW that can move over a set of high voltage transmission lines from one area to another.
Sales and Purchases on a Unit Basis	The exchange of electric power and energy from a dedicated generation plant.
Sales and Purchases on a System Basis	The exchange of electric power and energy from a provider's fleet of generation plants.
Simultaneous Transfer Capability	The amount of electrical output measured in MW that can move over all sets of high voltage transmission lines at the same time from one area to another.
With or Without Reserves	A contract specification for an exchange of power and energy in which the seller does or does not provide the additional capacity required so that the sale has the same high level of dispatch priority as native load.

Appendix A

Table A-1 New Utility-Owned or Leased Generation Capacity, 2008-2014

Year	Type of Load Served	Capacity (MW)	Name	New or Existing Site	Owner/ Leaser	Fuel	Location (County: Locality)	PSC Status & Docket #
2008	Base Load	515	Weston Unit 4	Existing site	WPS, DPC	SCPC coal	Marathon: Villages of Rothschild & Kronenwetter	Approved 6690-CE-187
2008	Base/Intermediate - Combined Cycle	575	Port Washington Unit 1	Existing site	We Power	Natural gas	Ozaukee: City of Port Washington	Approved 05-CE-117
2008	Non-dispatchable[1]	145	Blue Sky/ Green Field (88 turbines)	New site	WEPCO	Wind	Fond du Lac: Towns of Calumet & Marshfield	Approved 6630-CE-294
2008	Non-dispatchable[1]	99	Forward (66 turbines)	New site	Invenergy	Wind	Dodge & Fond du Lac: Towns of Byron, Oakfield, Lomira, & Leroy	Approved 9300-CE-100
2008	Non-dispatchable[1]	67.6	Cedar Ridge (41 turbines)	New site	WP&L	Wind	Fond du Lac: Towns of Eden & Empire	Approved 6680-CE-171
2008	Non-dispatchable[1]	30	Top of Iowa 3	Existing site	MGE	Wind	Iowa	Approved 3270-CE-126
2009	Base load[2]	615	Elm Road Unit 1	Existing site	WEPCO	SCPC coal	Milwaukee: City of Oak Creek	Approved 05-CE-130
2009	Peak load	55	Marshfield M-1	New site	Marshfield Utilities	Natural gas	Wood County: City of Marshfield	Approved 3420-CE-111
2009	Peak load	12	Concord Units 3 & 4	Upgrade to existing unit(s)	WEPCO	Natural gas	Jefferson: Watertown	Approved 6630-CE-300
2010	Base load[2]	615	Elm Road Unit 2	Existing site	WEPCO	SCPC coal	Milwaukee: City of Oak Creek	Approved 05-CE-130
2010	Non-dispatchable[1]	100	Crane Creek Wind Farm	New site	WPS	Wind	Iowa	Approved 6690-CE-194
2010	Non-dispatchable[1]	200	Bent Tree Wind Farm	New site	WPL	Wind	Minnesota	Under Review 6680-CE-173
2011	Base load[4]	90	Point Beach Units 1 & 2	Upgrade to existing unit(s)	WEPCO	Nuclear	Kewaunee: Town of Two Creeks	NA
2011	Peak load	100	Combustion Turbine (CT) #1	To be determined	Dairyland Power	Natural gas	To be determined	No application filed
2012	Base Load	300	Nelson Dewey (or Columbia) #3	Existing site(s)	WPL	SCPC coal	Grant: Village of Cassville (or Columbia: City of Portage)	Under Review 6680-CE-170
2014	Peak load	167	New CT #1	To be determined	WPS	Natural gas	To be determined	No application filed
2014	Peak load	167	New CT #2	To be determined	WPS	Natural gas	To be determined	No application filed
2014	Non-dispatchable[1]	100	Not named	Probably new	WPS	Wind	Probably not in Wisconsin[3]	No application filed
2016	Non-dispatchable[1]	100	Not named	Probably new	WPS	Wind	Probably not in Wisconsin[3]	No application filed

1 Nameplate MW shown. Wind operates when the wind blows: MW counted as firm are 20% per year ave. or less (more wind in winter than summer).
2 Elm Road Generating Station Units 1 and 2 will each be rated at 615 MW. Wisconsin Electric will lease 515 MW from each unit.
3 The higher wind speed in MN and IA provides higher, less-costly capacity (MW) than turbines located in WI.
4 Power sold to WEPCO by Florida Power & Light (FPL) under a Purchased Power Adjustment (PPA)

Table A-2 New Transmission Lines[1] (on which construction is expected to start by December 31, 2014)

PSC Status & Docket #	New Line or Rebuild/Upgrade2	Endpoints (Substations)	County	Voltage (kV)	Est. Cost (Millions)	Expected Construction	Expected In-Service	Substation Changes
American Transmission Company (ATC)								
Pre-application 137-CE-140	Use structures on existing line	Canal - Dunn Road	**Door**	138	9.10	Dec-11	Jun-12	Yes
Hearing Feb. 08 137-CE-149	New: Primarily add 2nd 345kV circuit to single-circuit line	Paddock - Rockdale	**Dane & Rock**	345	132.70	Oct-08	Jun-10	Yes
No application filed	rebuild 69-kV line to 138-kV	Brodhead - South Monroe		69 (built for 138)	10.10	Feb-11	May-11	
Application filed 137-CE-147	New	Rockdale - West Middleton	**Dane**	345	221.00	Jun-09	Jun-13	Yes
No application filed	Replace existing 69kV line w/double-circuit 161/69 kV. About 1.2 miles of 69 kV	Monroe Co. - Council Creek	**Monroe**	161	21.90	Jun-11	Dec-12	Yes
137-CE-153 6680-CE-170	New line for power plant outlet[3]	Nelson Dewey - Mississippi River	**Grant**	161	9.9	Jul-10	Jun-11	New switching station
Dairyland Power Cooperative (DPC) with Northern States Power - WI and Northern States Power - MN[4]								
Filed w/ MN PUC - WI PSC filing later	New 345kV line: possibly replace existing 69kV line from Alma Power Plant to N. LaCrosse	Hampton Corner (North Rochester-Twin Cities area) - La Crosse area	**Buffalo Trempealeu LaCrosse**	345	360	Jun-10	Dec-15	Yes (at North La Crosse Substation)
Northern States Power of Wisconsin (NSPW)[5]								
No application filed	New 161kV line to replace existing double-circuit 69kV line	Eau Claire - Hallie	**Eau Claire, Chippewa**	161	25.5	Oct-07	Jan-11	New Gravel Island Substation at intersection of existing lines
No application filed	New substation; no transmission line	New (Three Lakes) substation on Pine Lake - Willow River line	**St. Croix**	115	16.4	To be determined	May-09	New 115/69 kV Substation at crossing of Willow River-Pine Lake 115 kV line & Kinnickkinnick-Roberts 69 kV line
No application filed	New substation; less than 1 mile of new 161kV line	New substation to transfer Rush River substation load to Pine Lake-Crystal Cave 161 kV line	**St. Croix**	161	2.6	To be determined	May-09	New 161 kV Substation and upgrade of Rush Substation to 161 kV

1 Does not include lines approved by the Commission

2 Rebuilds and upgrades, as well as new lines, may require new right-of-way

3 An alternate plant site (Columbia) would likely require new switching stations (on existing lines) and possibly a rebuild

4 See Table A-03

5 Northern States Power - Minnesota has a Resource Plan that may possibly affect WI transmission (wind & combustion turbine facilities not yet sited).

Table A-3 More Detailed Information for New Transmission Line Proposed in Table A-2*

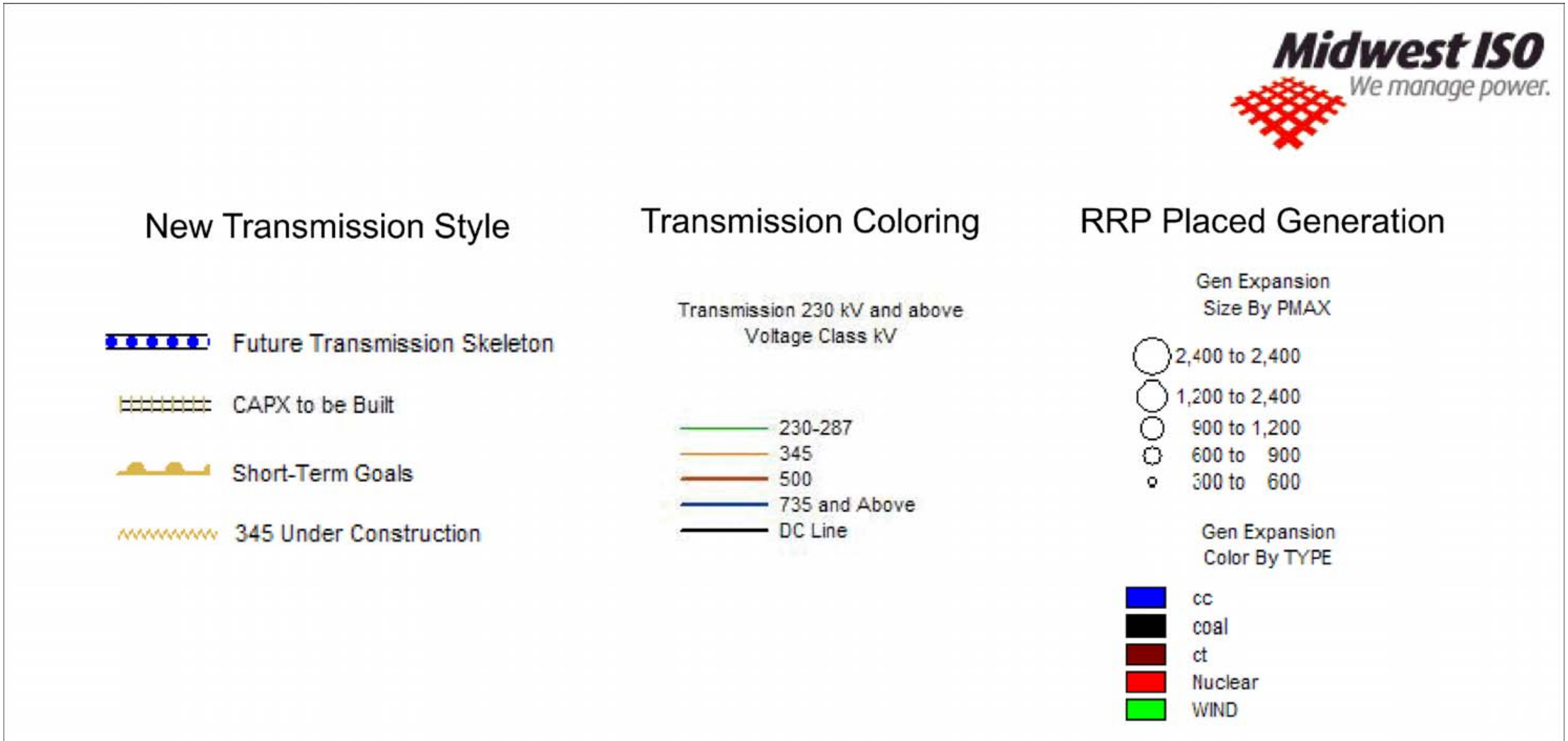
Project	Hampton Corners (MN) - LaCrosse Area 345 kV
Voltage (kV)	345 kV
Length (miles)	120-150 miles (about 40 miles in WI)
Screening Area	5500 sq. miles - Overall study area is 100 miles by 55 miles, covering both Minnesota and Wisconsin.
Corridor-sharing Opportunities	Wisconsin only - existing DPC and NSPW 161 and 69 kV lines, Highway 35
Public Lands	Upper Mississippi NationalFish and Wildlife Refuge, Trempealeau National Wildlife Refuge, Whitman Dam Wildlife Area, Perrot State Park, Merrick State Park, Van Loon Wildlife Area, Great River State Trail
Sensitive Resources	Blufflands, Mississippi River (numerous resources associated with this, including flyway issues and wetland issues), prairie remnants, wetland complexes, Waumandee, Black, Trempealeau and La Crosse Rivers,
Cultural Resources	There are numerous cultural resources within the study area
Miscellaneous	A Certificate of Need was filed with the Minnesota Public Utilities Commission on August 16, 2007. The docket number is ET02, E-002/CN-06-1115. Additional environmental information is available in that docket.

* Excludes projects already filed with the PSC and those proposed to center on existing right-of-way

Table A-4 Utilities' Proposed Emission Control Equipment Installation Estimates Used for EGEAS Modeling

UNIT	APPLICATION FILED WITH COMMISSION	YEAR ORIGINAL UNIT RETIRED	YEAR UNIT WITH CONTROLS INSTALLED
Columbia 1	No	2013	2014
Columbia 2	No	2011	2012
Edgewater 4	No	2010	2011
Edgewater 5	No	2012	2013
Nelson Dewey 1	Yes	2014	2015
Nelson Dewey 2	Yes	2013	2014
Oak Creek 5	Yes	2012	2013
Oak Creek 6	Yes	2012	2013
Oak Creek 7	Yes	2012	2013
Oak Creek 8	Yes	2013	2014
Pulliam 7	No	2013	2014
Pulliam 8	No	2013	2014
Valley 1	Yes	2013	2014
Valley 2	Yes	2014	2015
Weston 2	No	2014	2015
Weston 3	No	2013	2014

Figure A-1 Universal Legend for Transmission



Detailed analysis of those Projects already in Appendix B will be performed as part of MTEP08. However, most of the facilities identified in Step 3 of the MTEP08 process should generally be considered as conceptual; and, will be placed Appendix C for further analysis. Appendix C projects are not in the models but are available for MTEP analysis.

Figure A-2 MISO Centric Transmission Scenario

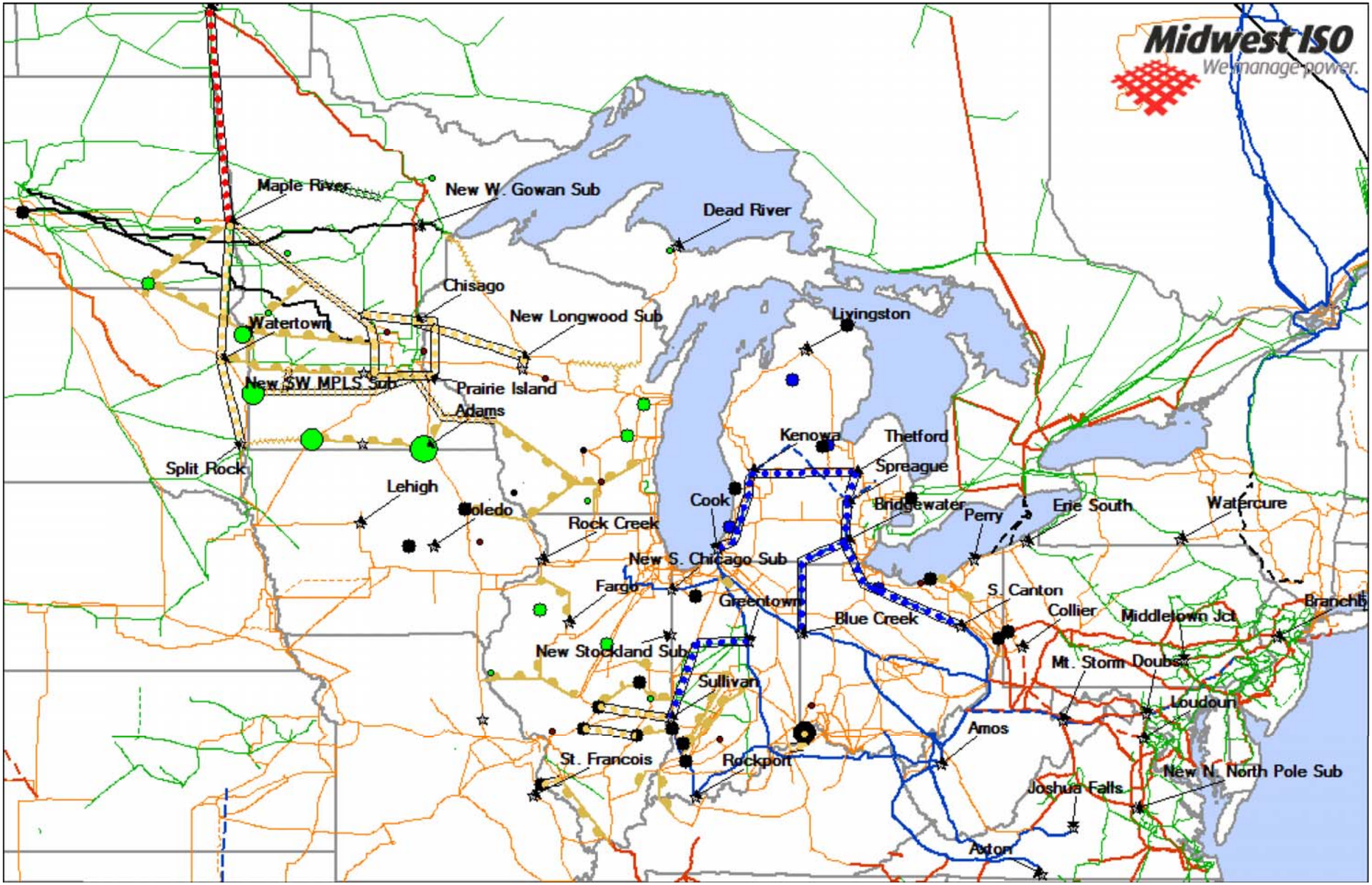
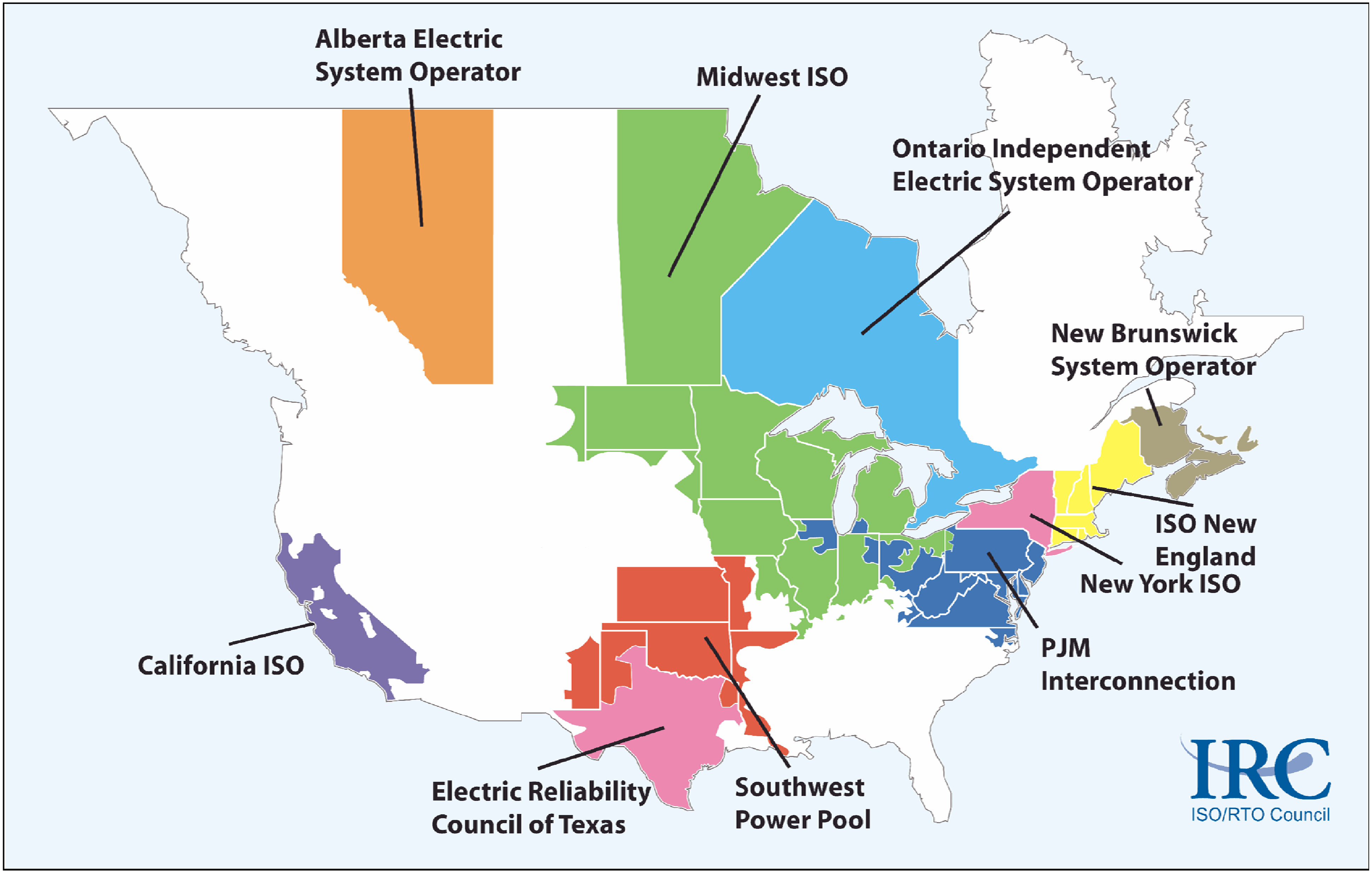


Figure A-3 Map of Regional Transmission Organizations



Appendix B

The Nine Planning Principles of FERC Order 890

1. **Coordination**—The transmission providers must meet with all of their transmission customers and interconnected neighbors to develop local and/or regional transmission plans on a non-discriminatory basis. Details such as meeting structures, responsibilities of parties, and how decisions are made are required.
2. **Openness**—The transmission planning meetings must be open to all affected parties including but not limited to all transmission customers and interconnection customers, state authorities, and other stakeholders. A process to manage confidential data such as Critical Energy Infrastructure Information is to be described
3. **Transparency**—The transmission provider must produce in writing and make available the basic methodology, criteria, and processes for developing transmission plans. This includes the planning cycle and milestones. The criteria used in the methodology must be described such as load flow, stability, short circuit, voltage collapse, production costs, etc. The assumptions regarding the transmission, generation, and demand response resources for model building are documented and a process for updates identified.
4. **Information Exchange**—The network customers are required to submit information on their projected loads and resources on a comparable basis and point-to-point customers on their service requirements. For the planning process the customers submit generation planned additions, upgrades, or retirement along with any environmental restrictions. Customers also submit existing and planned demand response resources and their impact on demand.
5. **Comparability**—The transmission plan must meet the specific service requirement of their transmission customers and treats similarly-situated customers the same in the planning process. The important change is to consider demand response as a resource, where appropriate, in planning.
6. **Dispute Resolution**—The transmission providers must identify a process to manage disputes that arise in the planning process. The steps of resolution are described in the negotiation, mediation, and arbitration, and only go to complaint to the Commission during the negotiation or mediation step.
7. **Regional Participation**—In addition to preparing a system plan for its own control area on an open and non-discriminatory basis, each transmission provider is required to coordinate with interconnected systems. This principle includes description of the interaction of local planning and regional planning activities. The use of sub-regional groups has been identified, and the description of inter-regional planning activities that could relieve congestion across multiple regions. The inter-regional coordination should strive for consistency in planning data and assumptions. A key and very important point is a description of the process for determining whether the transmission plans developed on a local, sub-regional, and inter-regional basis are simultaneously feasible.
8. **Economic Planning Studies**—The transmission providers must account for economic as well as reliability considerations in the transmission planning process. The process for requesting economic studies and procedures must be published along with the study information. The mechanism for recovering the costs incurred to perform the economic planning studies described and reflected in their OATT.
9. **Cost Allocation**—The cost allocation of new facilities that do not fit existing rate structures must be addressed. This includes the methodology for allocating costs associated with reliability and economic upgrades. Attachment K must describe the roles and responsibilities of the transmission provider and stakeholders during the cost allocation process.